Review of Offshore Oil-spill Prevention and Remediation Requirements and Practices in Newfoundland and Labrador

Appendix Documents

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Frequently Asked Questions Concerning Oil-spill Prevention and Remediation Requirements and Practices in Newfoundland and Labrador

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1 Who is responsible for responding to oil-spills off Newfoundland's coast?

Whereas Transport Canada is the lead federal agency for Canada's Marine Oil-spill Preparedness & Response Regime, Fisheries & Oceans Canada, namely the Canadian Coast Guard, is responsible for managing responses to ship-source oil-spills and for ensuring that the response is appropriate.

Certain vessels and oil-handling facilities are required to have emergency plans and to implement these plans in the event of a spill.

The Canadian Coast Guard provides a national preparedness capacity and manages the National Response Team and ensures an appropriate response to marine pollution incidents as the Federal Monitoring Officer or On-scene Commander (OSC).

Oil-spill response at an offshore platform falls under the jurisdiction of the C-NLOPB pursuant to Section 161 of the Atlantic Accord Implementation Act. The C-NLOPB has the mandate to ensure the operator is taking all reasonable measures to prevent further spillage and to mitigate the effect and impacts of a spill. Where reasonable measures are not being taken, the Chief Conservation Officer can direct the operator or can take over management of the response effort directly.

If a spill should occur, multiple parties will work together, including the CCG, C-NLOPB, DFO, Environment Canada, Provincial Government departments, and the Eastern Canada Response Organization.

2 Does CCG have adequate response equipment to deal with a large offshore spill?

Transport Canada ensures that the appropriate level of preparedness is available to respond to marine oil pollution incidents in Canada of up to 10 000 tonnes. The regime is built on the principle of cascading resources, which means that in the event of a spill, the resources of a specific area can be supplemented with those from other regions or from our international partners as needed. The ECRC also has significant oil-spill response equipment.

3 Is Canada strengthening its offshore enforcement capability?

The illegal release of oily wastes from ships travelling in Canadian waters is an ongoing issue and immediate challenge to the conservation and protection of the marine environment. As a result, Canada is continuing to enhance and strengthen its enforcement capability through vessel surveillance, Integrated Satellite Tracking of Pollution (ISTOP) program, air surveillance, stiffer penalties for marine polluters, and satellite (RADARSAT).

4 Does Government and industry provide oil-spill training to the public/fisherpersons?

A collaborative initiative to provide comprehensive oil-spill counter-measure training to fisherpersons in Newfoundland and Labrador had been undertaken by One Ocean (www.oneocean.ca). This training is no longer available, however, efforts should be made to revisit whether this oil-spill response capability is worthwhile.

5 Does the Coast Guard practice port state control in Placentia Bay?

The CCG does practice port state control inspections in Placentia Bay under the mandate of the Paris MOU. In fact the CCG has exceeded its inspections of foreign vessels by 25 per cent in 2009.

6 Who pays for oil-spill response off Newfoundland and Labrador?

Canada's Marine Oil-spill Preparedness & Response Regime is built upon the polluter-pay-principle, which makes the polluter liable for all response costs associated with an oil pollution incident. There are various compensation regimes available to pay for clean-up costs, such as ships' insurance and national and international funds.

A protection and indemnity association of shipowners and operators known as the International Group of Public and Indemnity Clubs offers insurance coverage to shipowners and charterers against third-party liabilities encountered in their commercial operations. In addition, there are currently three funds to assist in paying for clean-up costs:

- Ship-source Ocean Pollution Fund (Canada)
- International Oil Pollution Compensation Fund
- Civil Liability Convention (International)

Under the Canada Shipping Act, 2001, the Ship-source Ocean Pollution Fund (SSOP) is liable to pay claims for oil pollution damage or anticipated damage at any place in Canada, or in Canadian waters including the exclusive economic zone, caused by the discharge of oil from a ship. It is Canada's national Fund.

The SSOP Fund is intended to pay claims regarding oil-spills from ships of all classes and is not limited to sea-going tankers. In addition to persistent oil, it covers petroleum, fuel oil, sludge, oil refuse and oil mixed with wastes.

The 1992 International Oil Pollution Compensation Fund (IOPC) and the 1992 Civil Liability Convention (CLC) provide the international liability and compensation regime for pollution damage resulting from spills of persistent oil from tankers, whether carried on board as cargo or in bunkers. Under the CLC regime, the owners of a tanker are liable to pay compensation up to a certain limit for oil pollution damage following an escape of persistent oil from their ship. If that amount does not cover all the admissible claims, further compensation is available from the IOPC Fund if the damage occurs in a contracting state. The IOPC Fund is financed by levies paid by entities that receive certain types of oil in the ports of a contracting state.

7 What would happen if a large oil-spill occurred offshore Newfoundland and Labrador and we didn’t have enough response resources?

Newfoundland and Labrador, and Canada as a nation, are part of a worldwide effort to prepare for spills when they occur, as well as the prevention of incidents. Within Canada, there are a series of response organizations (RO’s) that are funded by industry to be prepared to respond to spills up to 3 500 tonnes in each region. These RO’s are required by Canadian legislation and monitored by Transport Canada. In addition, the CCG is responsible for being prepared to manage spills (10 000 tonnes) in Canada should it be necessary. In this role, the CCG maintains stocks of equipment and trained and experienced responders at strategic locations across the country. These resources can also be called upon if required.

Also, Canada has acceded to the International Convention on Oil Pollution Preparedness Response & Co-operation (1999) that allows us to call upon other nations that are party to this convention.

Therefore, there is a significant capability that can be brought to bear on an incident if necessary.

8 What systems are in place to prevent or properly address a large catastrophic oil-spill?

Prevention of oil-spills is a priority for Transport Canada and the Department has focused much effort in this area over the years. Canada’s National system of oil-spill preparedness and response is built upon a successful partnership between Government and industry. The CCG is the lead federal agency responsible for coordinating responses to all Ship-source spills in waters under Canadian jurisdiction and mystery spills south of 60° north latitude.

Oil-spill response plans are in place, and there are regular exercises between Transport Canada-certified response organizations and other organizations, as well as CCG exercises with the US Coast Guard. Transport Canada has an inspection process in place to ensure that ships entering Canadian waters meet applicable safety standards.

Department of Fisheries & Oceans (DFO) scientists have conducted specific studies on samples of hydrocarbons from our offshore oil and gas reserves to ensure that we have appropriate information for response plans. DFO scientists are on Regional Environmental Emergency Teams (REET) to ensure oil-spill response decisions have minimal impacts on our fisheries and fishers habitat. DFO also has several research programs underway to develop and evaluate oil-spill countermeasure technologies, in addition to their laboratory facilities and expertise to monitor the impact of oil spilled in the marine environment.

9 How many oil tankers are there in Canadian waters each year and where can most of them be found?

There are approximately 20 000 oil-tanker passages off the coasts of Canada each year. Of these, a total of approximately 17 000 are on the east coast of Canada.

10 Should Canada establish a marine protected area under the Marine Environmental Protection Committee?

Marine protected areas are increasingly being endorsed as a valuable conservation and protection tool. The drive for a Federal Marine Protected Areas Strategy ensued from the need for a cooperative and collaborative approach to the development of a network of federal marine protected areas in Canada as a means to help address the declining health of our oceans. In 1997, the Oceans Act provided Fisheries & Oceans Canada with a leading and coordinating role in this endeavor. To ensure that progress continues responsible departments and agencies will move forward in establishing areas that have been identified as candidate sites and identify additional sites for the future.

11 How does Canada deter marine polluters?

Deterring marine polluters is accomplished by maintaining prosecution rates, in-port inspections, surveillance, ship-traffic monitoring, investigation, detention, prosecution and convictions and fines.

12 Does Canada enforce the use of automated identification systems (AIS)?

AIS is a shipboard broadcast transponder system, operating in the VHF maritime band, which is capable of sending such ship information as identification, position, heading, ship length, beam, type and draught, hazardous cargo information, to other ships as well as to AIS Base Stations operated by a competent authority. It is capable of handling over 2 000 reports per minute and updates as often as every two seconds. It uses Self-Organizing Time Division Multiple Access (SOTDMA) technology to meet this high broadcast rate and ensure reliable ship-to-ship and ship-to-shore operation.

All domestic vessels of 500 tons or more exclusive of fishing vessels must be equipped with AIS as of July 1, 2008. In addition, CCG requires that all oil tankers entering Placentia Bay be equipped with AIS regardless of their country of origin or age.

The new Smart Boy buoy for the pilot boarding station (Placentia Bay) is equipped with ATONIS (Aids to Navigation Info System), which is effectively an AIS on a fixed structure. This allows all vessels having AIS to immediately see the buoy as well as access real-time data from the buoy that is displayed in the information bar on the ships ECS. The new buoy was deployed on June 12, 2010.

13 Should Canada reward those who file pollution reports leading to conviction?

Rewarding those who file pollution reports leading to conviction is practiced elsewhere in the world, and proves to be an effective remedy against chronic oil pollution. Such a remedy should be considered for Canadian waters.

14 Why is Newfoundland and Labrador so important to Canada's oil and gas industry?

Large amounts of crude oil and natural gas are located in sedimentary basins beneath the ocean's floor off Canada's shores. Canada's east coast has a very promising geology. The area is home to the Atlantic Margin, one of the country's major regions containing sedimentary rock - the kind that is most likely to contain crude oil and natural gas. The Atlantic Margin extends along the east coast from the US border all the way to Baffin Island. The Geological Survey of Canada estimates the Atlantic Margin could contain over 18 per cent of Canada's total conventional crude oil and natural gas resources.

- Significant crude oil and natural gas discoveries have been made off the east coast during the past 30 years;
- The Atlantic Margin could contain significant amounts of Canada's total conventional crude oil and natural gas resources;
- The east coast is close to energy-hungry markets in the United States and eastern Canada;
- Infrastructure is in place to service the industry and its markets;
- Improving offshore technologies.

15 Why is the offshore oil and gas industry important to Canada?

At the national level, the offshore industry has a positive impact on Canada's balance of trade - the difference between the amount of products imported and exported by a country - and improves the security of our energy supplies. The industry brings benefits to local economies, creates research and development opportunities, and raises the skill level of the workforce.

- Billions of dollars are pumped into the Canadian economy through capital spending and employment;
- The export of oil and gas has a positive impact on Canada’s balance of trade, which helps offset the country’s spending on imported goods and services;
- Profits earned by companies, and the expertise gained by their employees and contractors, help make Canadians leaders in the International petroleum industry;
- Governments benefit from the royalties and taxes paid by the offshore industry.

16 What impact has Hibernia, Terra Nova and White Rose had on Newfoundland and Labrador?

The Hibernia, Terra Nova and White Rose projects and the Sable Offshore Energy Project are the pioneers of Canada’s offshore industry. Together they are building the foundation for future offshore development. The projects have established an infrastructure of production and transportation facilities. They have also established a pool of talent and operating experience for the next generation of projects. This foundation has prompted major companies to expand their exploration activities, form alliances with key participants and use state-of-the-art technologies to build portfolios of possible future projects. Governments are also gaining experience in how to regulate the petroleum industry effectively and efficiently and to reap economic rewards without unduly hampering industry expansion.

17 How do local communities benefit from the offshore industry?

- More than one-third of the billions spent by the offshore industry go directly into regional and local economies;
- The offshore industry creates thousands of jobs and spurs employment in businesses such as offshore support, training, transportation, research and development and marine services;
- New industries are attracted by the availability of offshore oil and gas.

18 What is the C-NLOPB?

The Canada-Newfoundland and Labrador Offshore Petroleum Board was established in 1985 under the Atlantic Accord to regulate the offshore oil and gas industry on behalf of the Government of Canada and Newfoundland and Labrador. The Board is composed of 69 capable staff having approximately 600 years of combined experience in offshore oil and gas. The Board's mandate encompasses four key areas - worker safety, environmental protection, resource management, and industrial benefits. Its mission statement confirms that worker safety and environmental protection will be paramount in all Board decisions. The Board has no part in the establishment or administration of royalties or taxes for any offshore activity and does not promote the offshore industry. The Board's role is one of regulatory oversight of operator activity.

19 How is the environment protected during offshore exploration and production?

- No offshore activity can occur without an environmental assessment and regulatory approval.
- Geophysical vessels gradually increase sound levels at the beginning of seismic surveys so fish and mammals can move away from the immediate area.
- The industry uses specialized equipment to reduce the possibility of spills during drilling.
- Offshore facilities are designed for the particular environment where they will be located.
- Low-toxicity drilling fluids are used, and rock cuttings are separated from the fluid before they are disposed of.
- Double-hulled and double-bottomed tankers are used to transport crude oil from production facilities.
- Company and Government officials continually monitor environmental impacts.
- Restrictions are in place to protect sensitive marine environments.
- Companies work with the Coast Guard, spill-response organizations and other Government agencies to prevent spills and prepare for fast and effective response when necessary.
- Sophisticated risk-management methods are used to identify appropriate protective measures.

Steps in Emergency Prevention Planning include:

1) Identify site-specific safety/environmental hazards.

2) Plan operations and design equipment to eliminate/reduce those hazards.

3) Ensure workers understand equipment and know how to recognize and react to problems.

4) Continuously monitor and fix equipment before it fails and use fail-safe monitors, alarms and automatic shutdowns as a back-up program.

5) Ensure there is enough extra equipment and trained personnel on site to respond to an emergency.

6) Review any emergency event to prevent recurrence.

20 How are health and safety protected in the offshore industry?

The sinking of the drill rig Ocean Ranger in February 1982 on the Grand Banks off Newfoundland, with the loss of 84 lives, and the fire and explosion on the Piper Alpha production platform in the North Sea in July 1988, with a loss of 167 lives, opened all eyes to the harsh realities of offshore petroleum operations. Subsequent investigations revealed the need to improve safety planning and performance. Lessons learned from those accidents prompted Governments and industry to improve safety planning, systems and equipment in the offshore oil and gas industry. These enhancements include the development of comprehensive safety management systems and mandatory reviews of all safety hazards before projects or activities are approved.

21 When did drilling for oil and gas begin in Newfoundland and Labrador?

Drilling for oil and gas in the Newfoundland and Labrador area began over 40 years ago in 1966. Since that time, 355 wells have been drilled including 144 exploration wells. Fifteen wells have been in deepwater, which is considered to be 500 metres or more. Production of oil from our offshore area started in 1997. At the end of March 2010, 1.1 billion barrels of oil have been produced from three projects: Hibernia, Terra Nova and White Rose. Since the beginning of production, 1100 barrels of crude have been spilled - 1 barrel per 1 million produced. There have been no blowouts in our offshore area.

In 2010, there was one exploration drilling program taking place. Chevron Canada Limited drilled the Lona O-55 exploration well, 427 kilometres northeast of St. John’s at a water depth of approximately 2 600 metres.

22 What response mechanisms are available to Atlantic Canada operators?

- Oil-spill response equipment such as containment booms, skimmers, tracking devices are permanently stored on production facilities and on supply vessels. Additional equipment is stored on shore and can be quickly mobilized;

- Spill-response contractors Eastern Canada Response Corporation are available 24 hours a day to provide assistance. Oil-spill response Ltd., the world’s largest spill-response organization can also provide assistance within 24 hours;

- Many operators have special teams ready to be mobilized within hours to augment local response organizations;

- The Canadian Coast Guard, which has the largest inventory of pollution recovery equipment in Canada, is readily available with personnel and spill equipment; and
- Through mutual aid agreements, offshore operators and companies will provide spill-response support by lending equipment and allocating personnel to other offshore facilities, if needed.

23 What is a blowout?

A blowout is the uncontrolled flow of gas, oil or other fluids from a well that occurs when the pressure within the well exceeds the pressure in the borehole applied to it by the column of drilling fluid.

24 What is a blowout preventer?

A blowout preventer is a large valve that can seal off an oil or natural gas well being drilled or worked on. If underground pressure forces oil or gas into the wellbore, operators can close the valve remotely (usually by hydraulic actuators) to forestall a blowout, and regain control of the wellbore. Once this is accomplished, often the drilling mud density within the hole can be increased until adequate fluid pressure is placed on the influx zone, and the BOP can be opened for operations to resume.

25 What is a relief-well?

A relief-well is a well drilled near and deflected into a well that is out of control, making it possible to bring the wild well under control. The relief-well must be drilled to pump kill fluid into the producing formation and blowout wellbore.

26 What is the regulatory process for drilling programs offshore Newfoundland?

Before drilling programs are contemplated, before the relevant licenses are issued in a potential area of exploration, the C-NLOPB undertakes a Strategic Environmental Assessment, or SEA, of potential operations in that area. This initiative is over and above the requirements of both the Atlantic Accord Legislation and the current federal environmental assessment legislation. The SEA for the Orphan Basis area was undertaken in 2003 and included solicitation of public comments on both the scoping document for the SEA, at the outset of the process, and on a draft of the final report. The final report was posted on the Board's web site in November 2003 and is still available today. The SEA, while necessarily more of an overview nature than subsequent project-specific assessments, included consideration of potential blowout risk and fate.

As part of the planning process for a drilling program, and before any authorization respecting the program is issued, an environmental assessment of the proposed program is conducted. The assessment is conducted under both the federal Canadian Environmental Assessment Act and the Accord legislation. In the case of the Orphan Basin drilling program, for example, the assessment was concluded in July 2006, prior to authorization of Chevron's first well in the area, the deepwater exploration well Great Barasway F-66, The documentation associated with this assessment, like all such Board assessments, is publicly available and the principal documents still can be downloaded from the Board's website.

The Board's oversight of an offshore drilling program commences at the early planning stage, typically 18 months or more in advance of any proposed program. The operational review and approval of drilling programs is a two-tiered process that requires firstly, an Operations Authorization, and secondly, an Approval to Drill a Well for each well to be drilled as part of the drilling program.

Prior to receiving the Operations Authorization, a number of statutory obligations must have been met. The applicant must have completed the environmental assessment process required by both the Canadian Environmental Assessment Act as well as the Atlantic Accord Implementation Act. The operator must have obtained a Certificate of Fitness from an independent third party certifying Authority, a Letter of Compliance from Transport Canada for the drilling installation, and they must file a Safety Plan, an Environmental Protection Plan and a Contingency Plan that includes an Oil-spill response Plan. In addition, they must submit documentation respecting financial responsibility, and finally, they must provide a Declaration of Fitness, attesting that the equipment and facilities to be used during their program are fit for the intended purpose, the operating procedures relating to them are appropriate, the personnel employed are qualified and competent, and the installation meets all necessary Canadian standards. Only after all of this documentation is presented to and approved by the Board, may an operator proceed with the application.

Drilling and well-control are critical aspects of offshore operations and are addressed extensively in the regulatory framework. This involves a review of the operator's well planning and technical capabilities in respect of well and casing design, well-control matters, kick prevention and detection, establishment of severe weather operating limits, a review of emergency disconnect requirements and an assessment of the relief-well drilling arrangements. Emphasis is also placed on ensuring that all personnel have the requisite training in well-control and blowout prevention. A review is conducted to ensure suitable redundancy of the blowout prevention (BOP) control systems, in the event of any situation that could result in a disconnect from the well.

Oversight of these matters is achieved in a systematic approach through the Board's Safety Assessment System, which includes a review of the Operator's Safety Management System and confirmation that the operator has identified the hazards and the measures to be put in place to reduce the risk from these hazards to a level that is as low as reasonably practicable.

Last but not least, the Board's safety and environment professionals review the emergency response plans for the project, in the event that an incident occurs despite the preventative measures in place. These plans include an oil-spill response plan, which describes in detail the command structure the operator will put in place to respond to a spill event. It also describes the relationship with other operators' and Governments' plans and a description of spill-response resources available at site, in eastern Newfoundland, nationally, and internationally. Locally available resources include large containment and recovery systems - boom-and-skimmer systems - with fluid pumping capacities of over 50000 barrels per day each. Oil-spill response Plans are publicly available on the C-NLOPB website.

The second tier of the approval process involves the requirement to obtain an Approval to Drill a Well or ADW for each and every well drilled. The ADW must provide detailed information on the drilling program and well design, including the BOP equipment and the casing and cementing program as well as the geological prognosis. This application is reviewed by a multi-disciplinary team within the Board consisting of engineers, technicians, geologists, geophysicists and environmental scientists prior to the issuance of the ADW.

The drilling and production guidelines in place speak to all critical matters in relation to well barriers, blowout prevention and well-control including BOP stacks, casing and cementing matters as well as detailed requirements and expectations pertaining to the termination of wells. These guidelines reflect high standards and modern thinking with respect to drilling, cementing and well-control matters.

27 If a spill did occur offshore Newfoundland, how likely would it be for the spill to reach our shores?

Detailed modeling of the potential fate of a spill from our offshore drilling locations, using forty years of weather data, indicates that even if a large spill were to occur, it would be unlikely that oil would approach the Newfoundland and Labrador shoreline. Thus, scenes like we see on the coast of Louisiana would not occur here. The impacts of a spill occurring this far from the Canadian coastline nevertheless could be serious and would require immediate response, but it would be a situation substantially different from what occurred in the Gulf of Mexico.

Modeling of ocean patters has been considered in the development of Operator Emergency and Oil-spill response plans. In the event of an incident, modeling information would be supplemented by on-water and aerial-surveillance monitoring. Note: Although trajectory modeling shows that spills are very unlikely to reach the shoreline, trajectories for a hypothetical spill scenario at Hibernia show that it is likely that the spill or response equipment would encounter some seabirds or commercial fisheries resources.

28 How is the C-NLOPB addressing the Lona O-55 deepwater well offshore Newfoundland?

Chevron Canada Limited was issued an ADW for the Lona O-55 deepwater well after having met all the regulatory requirements under the Drilling and Petroleum Regulations and associated Board guidelines. Chevron's Safety Plan identified all hazards, including blowout, and described how these hazards would be managed. Their Safety Plan described the use of appropriate equipment, proper procedures and competent personnel to undertake safe drilling operations. Chevron used the *Stena Carron* drill ship, which is a state-of-the-art, sixth-generation harsh environment drillship.

The BOP could be activated from the drill floor using either of two hydraulic control systems. This redundancy helps ensure that the well can be shut in by the drilling crew. The vessel also had three back-up systems capable of activating the BOP and shutting in the well should the need arise to do so - it had the acoustic system; Remotely Operated Vehicle (ROV) intervention capability, and an automode function (AMF), which automatically activates the BOP and shuts in the well when the signal is lost.

The Lona O-55 well was spudded on May 10, 2010. The BOP was fully pressured and function tested, including back-up activation systems, and was run in preparation for it to be run on riser and installed on the wellhead. Chevron continued to conduct drilling operations as per the approved ADW and the well was completed early September, 2010.

29 Has the Board taken extra precautions in light of the Macondo accident?

It is prudent practice for a regulator to conduct an internal review following an incident like the one in the Gulf of Mexico to determine if more can be done from an oversight perspective to address concerns about the risks of offshore drilling. In light of the situation that unfolded in the Gulf of Mexico and due to the heightened public concern over drilling operations currently underway in the Newfoundland and Labrador offshore area, the Board has taken the following measures for overseeing well operations at Chevron's Lona O-55 well. These measures were in addition to requirements contained in the Drilling and Production regulations and associated guidelines.

A team was established within the Board to provide regulatory oversight of Chevron's operations. This team was composed of the Chief Safety Officer, the Chief Conservation Officer, members of the Board's Management Team and selected senior staff having extensive experience in the regulatory oversight of drilling programs. Chevron was expected to ensure the timely posting of daily reports (seven days a week) so that up-to-date information was always available to this team.

Chevron was required to meet with the Board's oversight team every two weeks to review everything associated with the well. The Board's Chief Safety Officer chaired these meetings.

Chevron was required to provide the Board's Well Operations Engineer with copies of the field reports prepared in respect of the following: testing of the blowout preventer stack; function test of the acoustic control system; function test of the Remotely Operated Vehicle intervention capability and function test of the automode function system, together with an assessment of the readiness of the ROV system in terms of equipment, procedures and spare parts.

Chevron was expected to monitor developments at the Macondo incident and provide periodic assessments on the impact of any lessons learned from that situation to operations at Lona O-55, in particular any lessons learned with respect to well operations, BOP equipment or spill-response readiness.

The frequency of audits and inspections on board the *Stena Carron* were approximately every three to four weeks. Normally, audits and inspections are conducted on offshore operators every three to four months.

Prior to penetrating any of the targets, Chevron must hold an operations time-out to review and verify, to the satisfaction of the Chief Safety Officer and the Chief Conservation Officer, that all appropriate equipment, systems and procedures were in place to allow operations to proceed safely and without polluting the environment.

Chevron also made arrangements for a representative of the Board to be on board the *Stena Carron* to observe the cementing operations of the last casing string set prior to entering any target zones. The observer was also be present to witness the BOP testing, well-control drills, and results of the pressure test of the cementing job.

In the case of the BOP testing, a representative of the Certifying Authority was also present.

In due course, Chevron provided, for review and assessment by the Board's oversight team, a copy of the proposed well termination program to be issued to field personnel for implementation.

Chevron also made the necessary arrangements for a representative of the Board to be on board the *Stena Carron* to observe the well termination program.

The Board is confident that it administers a robust safety and environmental protection regime. Operators offshore Newfoundland and Labrador work in a harsh environment, which demands diligence on their part to reduce risks as low as reasonably practicable.

30 Should Newfoundland and Labrador have imposed a deepwater drilling moratorium in the wake of the Macondo accident?

The Macondo accident was an isolated incident and we must wait until the investigative findings are submitted in order to understand the cause of the disaster and benefit from lessons learned. New technologies, better safe-working practices and continued regulator oversight has resulted in fewer accidents over the past twenty years.

We must continue deepwater drilling and produce our own oil / energy and not rely on foreign imports by large oil tankers, which may pose a greater oil-spill risk than that of offshore exploration and production.

A moratorium would have serious economic impacts on Government, industry, communities, workers, service providers, and loss of domestic energy supply.

The risks vary from well to well including environment, geology, well configuration and characteristics and safety practices etc. Whereas we must always be vigilant, we must consider the economics, social and environmental values.

31 How does the C-NLOPB differ from the Minerals Management Service (MMS) in the United States?

The C-NLOPB was created in 1986 through the Atlantic Accord for the purposes of regulating the oil and gas industry offshore Newfoundland and Labrador. The Board operates at arms length from Governments and reports to both the Federal and Provincial Ministers of Natural Resources. Unlike the U.S., the C-NLOPB has no part in the establishment or administration of royalties or taxes for any offshore activity. The Board provides required data and information to Governments.

The U.S. practices a prescriptive approach to regulating its offshore oil and gas activities. Countries such as Canada, Norway, United Kingdom and Australia practice a performance-based and prescriptive approach that is a more effective regulatory regime for improving safety and environmental protection. Canada practices Goal-oriented regulation, which is a hybrid approach that includes prescriptive and goal- or performance-based elements. Performance-based regulation in the oil and gas industry began in 1988 when the Piper Alpha platform caught fire and sank in the North Sea, killing 167 people. Lord Cullen, who led the public inquiry and undertook to develop recommendations to prevent recurrence of such a disaster rejected a prescriptive approach and developed comprehensive objectives and made 106 specific recommendations to initiate a new and improved safety regime. Operators must provide full details for managing Health, Safety and Environmental issues. The goal-oriented approach is used so that operators can choose the best methods available to achieve the objective. The outcome of the trend from prescriptive-to performance-based regulation is that reportable offshore accidents have declined more than 75% by 2001.

Canada, being influenced by this approach adopted a unique hybrid approach and practices a mix of prescriptive-and goal-based styles of regulation. They contain Sections that provide prescription where deemed necessary and provide for latitude in the achievement of certain targets or results where appropriate. It is felt that moving from a prescriptive regulatory structure to one where the details of how to comply with the regulators are increasingly the responsibility of the regulated entity and results in more effective regulation. Goal-oriented regulations permit flexibility, good judgment and experience to determine the most cost-effective and efficient solutions to protect people, property and the environment.

The Canadian, Norwegian, United Kingdom and Australian practices and standards are more stringent than the United States. For example, the U.S. ceded responsibility to the oil industry for the design of key safety systems and features of offshore rigs. The U.S. oil industry, not the federal agency that regulated it (MMS), plays a crucial role in writing the safety and environmental rules for offshore drilling, a role that critics say reflects cozy ties between industry and the regulators. Another difference is that the MMS is responsible for regulating offshore drilling, but also for leasing tracts on the outer continental shelf and collecting royalties on the oil they produce. So while one arm of the agency is trying to make money, the other tries to regulate an industry where pumping oil sometimes trumps safety and environmental values.

32 Where are we in relation to green, renewable energy?

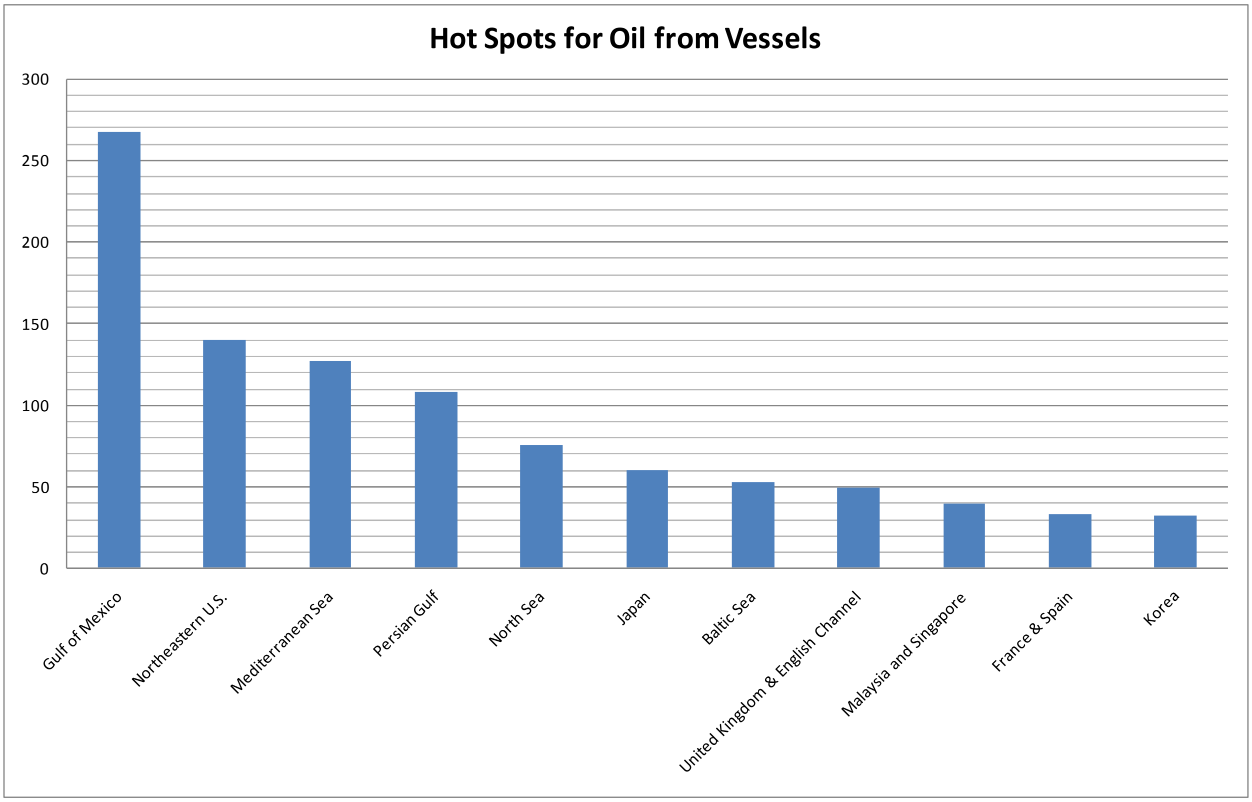
The argument for green fuels / renewable energy deserves merit. Whereas most of us endorse the rationale, the reality is that it won't happen in our lifetime. Whereas most of us endorse the rationale, the reality is that it is unlikely to happen in our lifetime.

We all need energy to survive and we should encourage the pursuit of greener energy sources. However, given our current technology limitations, the need for massive new investment and infrastructure, turnover timelines of capital stock and deployment lags, it will be decades before we can transition to a low-carbon or emission-free economy. Consequently, even as we push research and accelerate the deployment of renewable energy forms, we need to ensure that the conventional fuels system remains robust - and that includes the production and use of petroleum and natural gas (albeit cleaner) if for no other reason than there simply are no scalable alternatives available today (The Centre for Strategic and International Studies).

33 Where do most oil-spills happen in the world?

Oil-spills happen all around the world. Analysts for the Oil-spill Intelligence Report, who track oil-spills of at least 10 000 gallons (34 tons), reported that spills in that size range have occurred in the waters of 112 nations since 1960. But they also reported (Etkin 1997) that oil-spills happen more frequently in certain parts of the world. They identified the following “hot spots” for oil from vessels:

Region	Number of Spills
The Gulf of Mexico	267
The northeastern U.S.	140
The Mediterranean Sea	127
The Persian Gulf	108
The North Sea	75
Japan	60
The Baltic Sea	52
The United Kingdom and English Channel	49
Malaysia and Singapore	39
The west coast of France and north and west coasts of Spain	33
Korea	32



34 Do most oil-spills originate from tankers?

No, as long as you consider spills of all sizes. But tanker accidents have accounted for most of the world's largest oil-spills. They are less frequent than other kinds of oil-spills, such as pipeline breaks, but typically involve large volumes of spilled oil relative to other kinds of oil-spills. The Oil-spill Intelligence Report found that of the 66 spills in which at least 10 million gallons (34 000 tonnes) of oil were lost, 48 were from tankers. Eight were from fixed facilities, especially storage tanks, five were from production oil wells, three were from pipelines, and two were from other kinds of cargo vessels.

35 It appears the response operation in the Gulf of Mexico was, at times, inadequate. How does Canada's response regime differ from that of the U.S. Coast Guard?

The U.S. employs a Unified Command structure for coordinating federal response to incidents such as the spill in the Gulf of Mexico. This system was structured in California initially, for use in fighting forest fires. It has since been adopted by many other countries to deal with all types of emergencies including natural and man-made emergencies.

In the U.S., a phalanx of fourteen Government departments (each with its own vito power over decision making) are involved. Whereas the U.S. Coast Guard (USCG) appoints an Incident Commander, he/she has little say or power over the other Government departments involved, such as the National Oceanic and Atmospheric Administration (NOAA), Environmental Protection Agency (EPA), Occupational Safety and Health Administration (OSHA), Fish and Wildlife, National Parks, Minerals Management Service (MMS), as well as the various Gulf states who are affected by the spill. Each agency operates as the final authority within their respective area of jurisdiction and responsibility. Such a structure has obvious deficiencies because there is no dedicated and consistent line of control/command. Under U.S. law, the entity that caused the pollution is responsible for the clean-up (as they are in Canada), however, Government takeover is not permitted.

In contrast, Canada has a stronger command and control structure with the Canadian Coast Guard (CCG) as Lead Agency, supported by many other federal departments such as the Department of Fisheries and Oceans (DFO), Department of National Defense (DND), Natural Resources Canada (NRC), Transport Canada, Royal Canadian Mounted Police (RCMP), Health Canada, Public Safety Canada, and all Canadian Provinces and Territories etc.

The Canadian legal system is different from that of the U.S. in that it stipulates that in the case of a marine spill incident, although the polluter is in principle responsible for the spill cleanup, the Canadian

Coast Guard takes on the role of Federal Monitoring Officer (FMO). If the FMO determines at any time that the polluter is either unwilling or unable to respond to the incident, then the CCG can take full control and command over the entire operation.

The Canadian legal approach was introduced after the *Exxon Valdez* spill. Therefore, if an incident such as the Macondo spill were to occur anywhere in Canadian waters, the CCG would assume responsibility, if deemed necessary, respond to the spill and send the final invoice to the polluter.

36 Is there independent monitoring of accidental spills or discharges from loading and offloading platforms, offshore installations etc.?

There is no independent monitoring of accidental spills. All operators are audited for compliance with Section 9 of the Drilling and Production Guidelines that outline the operator's Environmental Protection Plan requirements and they are subject to the Board's Incident Reporting and Investigation Guidelines. Refer to the Board's decision report on the application for approval of the White Rose Development Plan Re: Third-party observers at: http://www.C-NLOPB.nl.ca/pdfs/sr/dec_report.pdf. Further, operators are required to report all spills to the C-NLOPB and this information is posted to the Board's website.

37 Is there adequate tug-boat support situated in Placentia Bay to respond and control a VLCC (Very Large Crude Carrier) if it loses control or becomes grounded?

There are currently four tugs stationed in Placentia Bay. Two tugs operate under Newfoundland Transshipment Limited (NTL), and two tugs operate under the North Atlantic Oil Refinery.

NTL did conduct model testing of their Voith-Schneider (VS) tug design for the Placentia Pride and the Placentia Hope. In late September, 2002, NTL decided to conduct full-scale tests of their tugs' capabilities These trials were conducted to measure the tug's effectiveness during performance and emergency assist maneuvers with the 127 000 DWT shuttle tanker M/T Vinland. Results from these trials were compared against original emergency maneuver simulations as contained in the Tug Operations Manual and Escort Plan. This previous data formed the basis of safety procedures for escorting tankers to and from the NTL terminal at Whiffen Head. The actual capability of the escort tug Placentia Pride was greater than the predictions. The recorded advance and tanker distances for emergency maneuvers to stop a laden 127 000 DWT shuttle tanker, with a hard over rudder situation, initially traveling at 10 knots, were found to be 800 and 550 metres, respectively. Generally, the results were better than predicted and indicate that the maneuvering data contained in the Tug operations Manual and Escort Plan is conservative (NTL Tanker - Tug Trials).

Based on the above findings, NTL is confident that their tugs are capable of providing adequate escort to fully laden vessels of the size that would normally call at NTL's Terminal. NTL is currently working with CanshipUgland to develop an ongoing program of emergency maneuvers during regular escorts that will maintain the level of skill for Masters and Officers that they feel necessary to ensure quick and capable action in the event of an emergency.

38 If there is an oil-spill, who is in charge?

Oil-spill response at an offshore platform falls under the jurisdiction of the C-NLOPB pursuant to section 161 of the Atlantic Accord Implementation Act. The C-NLOPB has the mandate to ensure the operator is taking all reasonable measures to prevent further spillage and to mitigate the effect and impacts of the spill. Where reasonable measures are not being taken, the Chief Conservation Officer can direct the operator or can take over management of the response effort directly.

The C-NLOPB is the designated lead agency in offshore spill incidents at offshore Newfoundland and Labrador drilling sites under a MOU with a variety of federal and provincial ministries (includes Environment Canada, Canadian Coast Guard, DFO, TC and Provincial Government departments).

For activities that fall under the Canadian Shipping Act such as supply vessel and tanker operations outside of the safety zone, shore-based operations and drill or production vessel shipyard, the vessel or facility operator will be the responsible party under the CSA.

It should be noted that although there will be a designated lead agency (such as the C-NLOPB) with oversight of the incident, multiple parties will work together during a cleanup including Government agencies referred to, other operators, ECER, etc.

Review of Offshore Oil-spill Prevention and Remediation Requirements and Practices in Newfoundland and Labrador

December 2010

Appendix II

Physical Environment of Newfoundland and Labrador and Comparisons to Selected Jurisdictions

Appendix II - Physical Environment of Newfoundland and Labrador and Comparisons to Selected Jurisdictions

1.0 Introduction

This document examines the physical environment of Newfoundland and Labrador's offshore oil and gas region. In addition, it provides a comparison to other comparable jurisdictions, including the North Sea and Norwegian Sea, the Gulf of Mexico and Australia. Detailed assessments of each jurisdiction are provided in Appendix III. The areas of interest are shown in Figure 1. These regions were selected because they were thought to possess oil-spill prevention and response standards and practices of comparable quality to Newfoundland and Labrador's offshore industry.

Figure 1 - Regions of Comparison

Source: (Printable World Map, 2010)

The purpose of this comparison is twofold. The first is to determine if any differences in regulation or practice between regions are primarily a result of their respective physical environments. An obvious example is that the Gulf of Mexico has no need for regulations regarding iceberg management, whereas Newfoundland and Labrador surely does. The second is to determine if there are any deficiencies in Newfoundland and Labrador's regulations and practices with respect to its own unique physical environment.

For each region, a summary of characteristic climatology (temperature, precipitation, wind and tropical storms), oceanography (bathymetry, ocean currents, sea surface temperatures, waves and ice hazards) and geology (coastal environments, surficial sediments, lithostratigraphy and seismicity) is presented (Appendix III for comparable jurisdictions). Section 2 examines the physical environment of the Newfoundland and Labrador offshore area, with Section 3 compares Newfoundland and Labrador to the other regions of interest.

2.0 Newfoundland and Labrador

2.1 Introduction

The Island of Newfoundland has a coastline approximately 9 655 kilometres in length and consists of thousands of bays, coves and inlets. Canadian sovereign territory extends 380 kilometres from the Province's coast, which equates to roughly 1.1 million square kilometres of ocean. As of 2002, over 90% of Newfoundland and Labrador's population lives on or within a few kilometres of the coast (Government of Newfoundland and Labrador, 2002).

The main offshore oil and gas industry in Newfoundland is currently concentrated on the Grand Banks, where waters are typically less than 200 metres deep. However, exploration is occurring in other regions, such as the Orphan Basin, at depths of more than 2 500 metres. There is also a great deal of tanker traffic in and around Placentia Bay, where the Transshipping Terminal is located.

The Grand Banks are widely regarded as some of the harshest oceanic environments in which oil and gas operations take place. This is a result of three major influences: (i) They are located at the convergence of three major storm tracks in North America (Milrad et al, 2009), including those associated with tropical storms; (ii) at the relatively unsheltered convergence point of two major ocean currents upon a shallow continental shelf (the North Atlantic Current and the Labrador Current); and also (iii) in the path of sea-ice and icebergs that typically travel southeast along the Labrador Current.

Figure 2 shows the geography and bathymetry (500 metre intervals) of Newfoundland's offshore region.

2.2 Climate

The atmospheric circulation is typical of mid-latitude locations, with a prevailing westerly flow, embedded with high and low-pressure systems. The background flow is stronger in the winter seasons, due primarily to the increased temperature gradient between the tropics and polar region, resulting in a greater availability of kinetic energy in the atmosphere. The higher energy results in stronger winds and low-pressure systems.

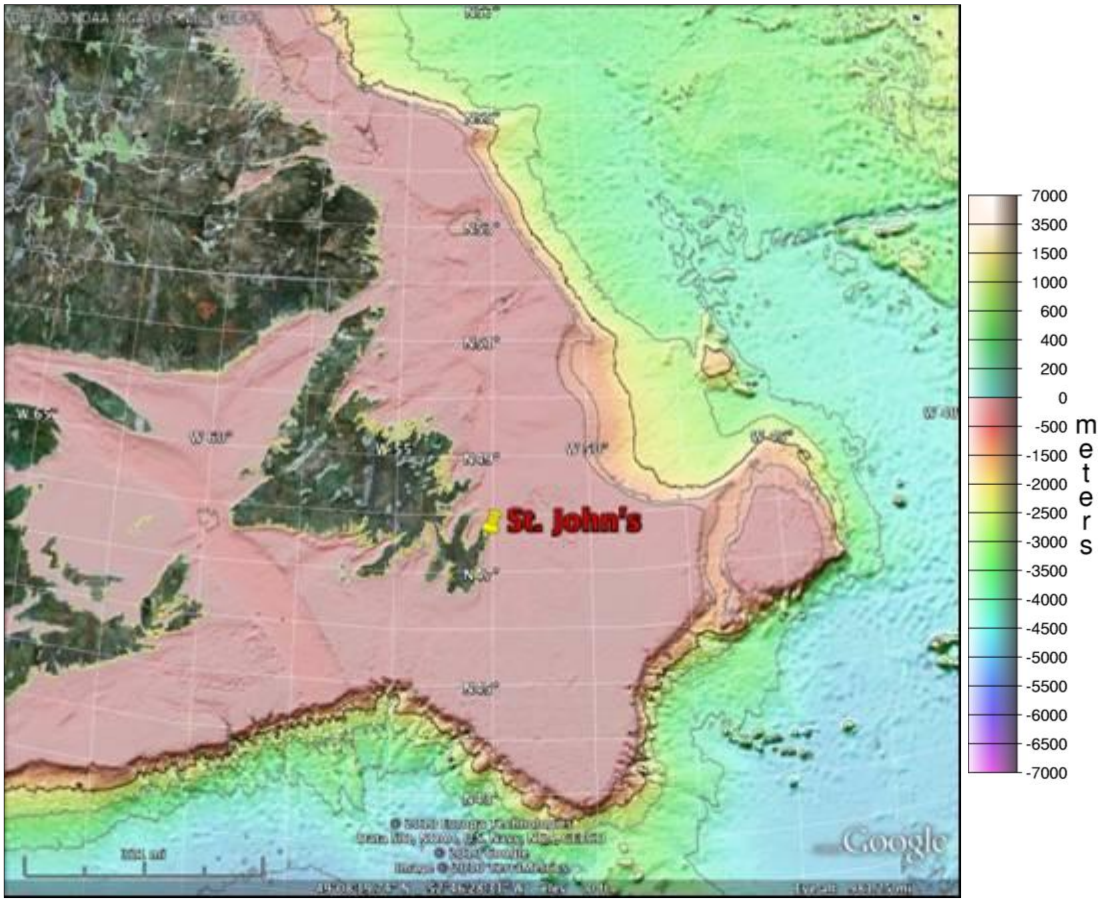


Figure 2 - Geography and Bathymetry (500 metres isobaths) of Newfoundland

Source: (Google Earth using Global Topography V12.1)

The region is also affected by tropical storms (including hurricanes), the season for which lasts from June to November, with the greatest risk from August to October. Tropical storms of all types weaken as they track over the relatively cold waters off Newfoundland and their resulting characteristics can vary widely.

During the summer there is less kinetic energy available in the atmosphere resulting in weaker winds and low-pressure systems. The prevailing storm tracks move farther north but still often travel south, intercepting Newfoundland and the Grand Banks (White Rose, 2000).

This section discusses Newfoundland's precipitation, mean and extreme surface air temperatures and wind speeds, as well as tropical storms.

2.2.1 Temperature

Table 1 displays climatological conditions for St. John's, NL, the closest city to the majority of offshore operations. The mean climatological maximum and minimum monthly temperatures are 21°C and -9°C, respectively, whereas record maximum and minimum temperatures are 34°C and -29°C, respectively. The temperatures experienced in an offshore environment within the vicinity of St. John's would be strongly moderated by the effects of the ocean. As such, minimum temperatures would typically be higher offshore whereas maximum temperatures would typically be lower.

Table 1 - Climatological Conditions for St. Johns, Canada (47.57 N, 52.71 W)

Month	Temperature (°C)				Average Precipitation (mm)	Wet Days (>0.25 mm)
	Average		Record			
	Min	Max	Min	Max		
Jan	-8	-2	-28	15	135	15
Feb	-9	-2	-29	13	125	15
March	-6	1	-26	19	117	15
April	-1	5	-18	22	107	15
May	2	10	-7	27	91	15
June	7	16	-3	31	89	13
July	11	20	1	32	89	13
Aug	12	21	0	34	94	13
Sept	8	17	-2	29	97	14
Oct	4	12	-6	31	135	16
Nov	0	6	-14	20	150	17
Dec	-4	1	-20	16	140	17

Source: (BBC World Weather)

Figure 3 shows maps of the climatological (1979 to 2009) mean surface air temperature for February and August, respectively. Newfoundland's mean offshore surface air temperatures range from -5 to 5°C in February and from 12 to 17°C in August.

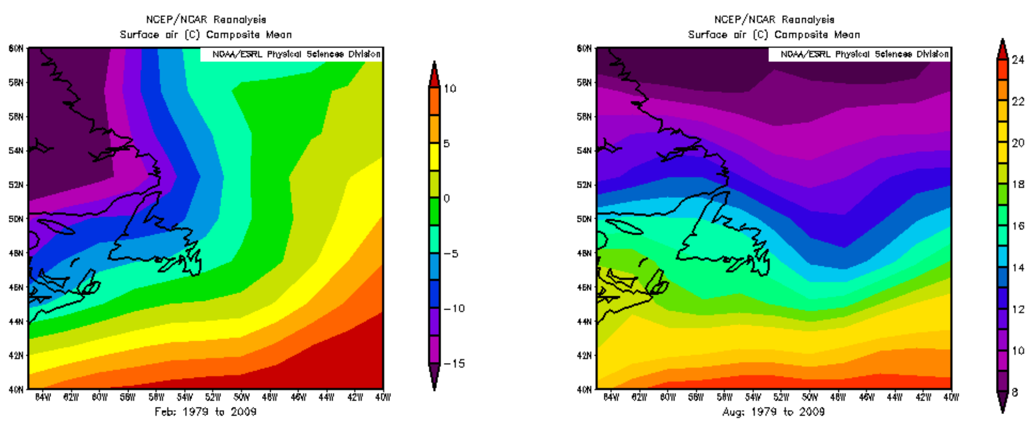


Figure 3 - Climatological Maps for Mean February (left) and August (right) Surface Air Temperatures

Source: (NOAA/NCEP Reanalysis Data)

2.2.2 Precipitation

As per Table 1, an average of 114 mm of precipitation per month (roughly 3.8 mm/day) falls in St. John's, with maximum precipitation occurring in the fall and winter (up to 150 mm per month) and minimum precipitation occurring in late spring and summer (as little as 89 mm per month). There is an average of 15 wet days (days with more than 0.25 mm of precipitation) per month in St. John's. Figure 4 shows the mean daily precipitation rates for February and August offshore Newfoundland.

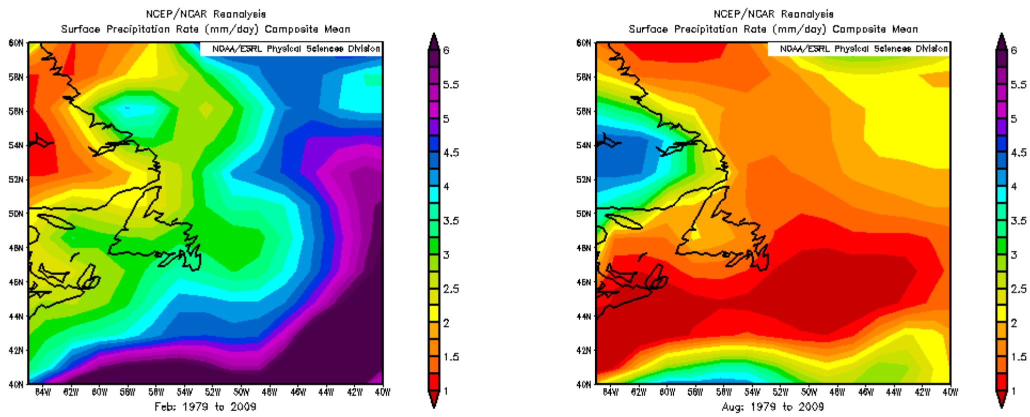


Figure 4 - Climatological Maps for Mean February (left) and August (right) Daily Precipitation Rates

Source: (NOAA/NCEP Reanalysis Data)

Depending on the season, precipitation can occur offshore Newfoundland in a liquid state (e.g., rain, drizzle), a solid state (e.g., snow, hail, graupel) or as a super-cooled liquid that freezes upon contact with a solid object (e.g., freezing rain or drizzle). Fog that can drastically reduce visibility also commonly occurs, as does ice accretion on structures resulting from sea spray (White Rose, 2000).

2.2.3 Visibility

Whereas there are several mechanisms for reducing visibility in the atmosphere, including smoke, drizzle, and haze, fog is by far the most prevalent offshore Newfoundland. In thick fog, visibility can be reduced to as low as 50 metres. In a typical July, the foggiest month, up to 50% of weather observations are taken in foggy conditions (White Rose, 2000).

Figure 5 shows the average number of days that experience fog based on observations from 1971 to 1999. The Grand Banks have more than 90 days per year with fog, while the Placentia Bay region is likely to experience over 120 days with fog.

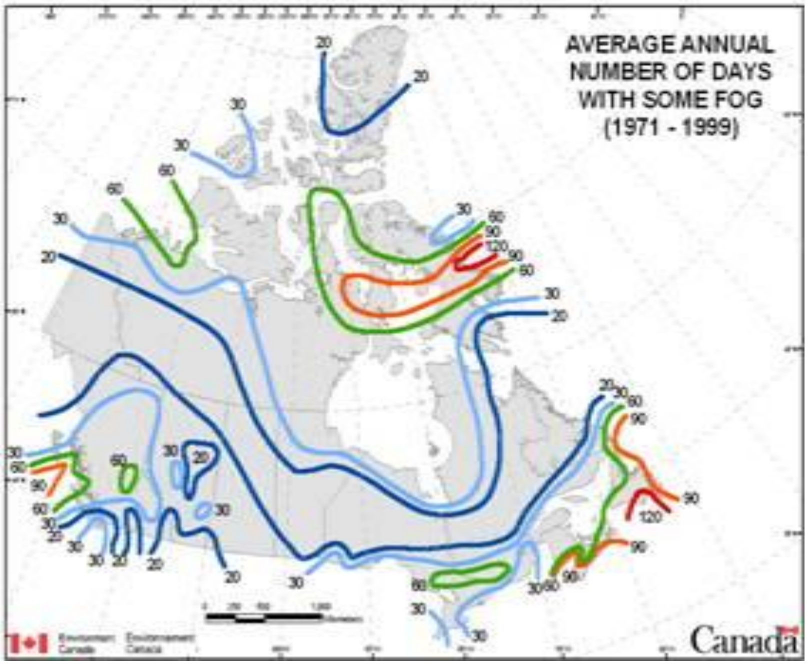


Figure 5 - Observed Fog Climatology of Atlantic Canada (1971 to 1999)

Source: Modified from (Muraca et al, 2001)

2.2.4 Ice Accretion

Causes of ice accretion on offshore structures include freezing sea spray, freezing precipitation, wet snow or super-cooled fog, the most severe of which is freezing sea spray. Air temperatures less than or equal to -4°C and winds greater than or equal to 17.5 m/s are the ideal conditions for the freezing of sea spray onto structures, even if the sea surface temperature is as high as 6°C. Significant amounts of ice can build up if the conditions persist for 12 hours or more (White Rose, 2000).

2.2.5 Wind

Figure 6 shows maps of the mean surface wind speed for February and August. As is typical of mid-latitude locations, the winds are stronger throughout the region in the winter than in the summer. In February the mean surface wind speeds over the Grand Banks range from 8.5 to 10.5 m/s, with stronger winds farther offshore, and in August the mean surface wind speeds are from 6.5 to 7.75 m/s.

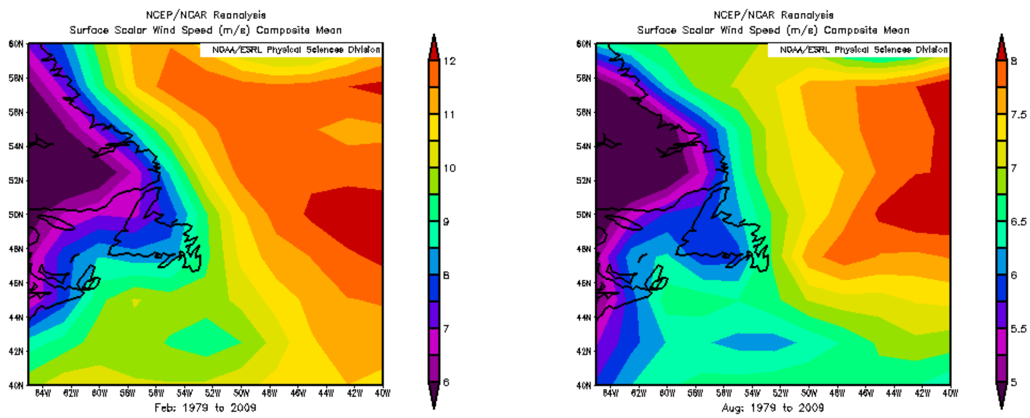


Figure 6 - Climatological Maps for Mean February (left) and August (right) Surface Wind Speed

Source: (NOAA/NCEP Reanalysis Data)

Table 2 shows the strength of various sustained wind speeds and their respective return period for the White Rose location (46.88 N, 48.33 W). On the extreme ends of the scale, one can expect a 3-second gust of 43.6 m/s once every 100 years (on average), whereas a 1-hour mean sustained wind of 23.6 m/s should be expected once every year (on average).

According to a global hindcast study for 1958 to 1997 (Cox and Swail, 2001), the mean annual 6-hour wind speed off of the east coast of Newfoundland was 8 to 9 m/s, whereas the 99th percentile annual 6-hour wind speed was 19 to 21 m/s, with values decreasing toward the coast. These results appear consistent with those found in the AES40 hindcast of Table 2. It should be noted that tropical storms and their associated waves were not well resolved in the Cox and Swail study.

Table 2 - Extreme Wind Speed Return Periods for the Grand Banks

Return Period (years)	1-hr mean (m/s)	10-min mean (m/s)	1-min mean (m/s)	15-sec mean (m/s)	3-sec mean (m/s)
1	23.6	25	28.8	31.2	33.7
10	27.7	29.4	33.8	36.6	39.6
25	28.8	30.5	35.1	38	41.2
50	29.7	31.5	36.2	39.2	42.5
100	30.5	32.3	37.2	40.3	43.6

Source: Atmospheric Environment Services of Environment Canada 40-year continuous hindcast of the North Atlantic Ocean (AES40) available from (White Rose, 2000)

2.2.6 Tropical Storms

Tropical storms originating in the tropical Atlantic Ocean frequently travel as far north as Newfoundland. Figure 7 shows the paths and intensities of all recorded tropical storms in the Newfoundland region for nearly 150 years. Whereas most storms are below hurricane strength, many Category 1 and several Category 2 hurricanes have entered the region.

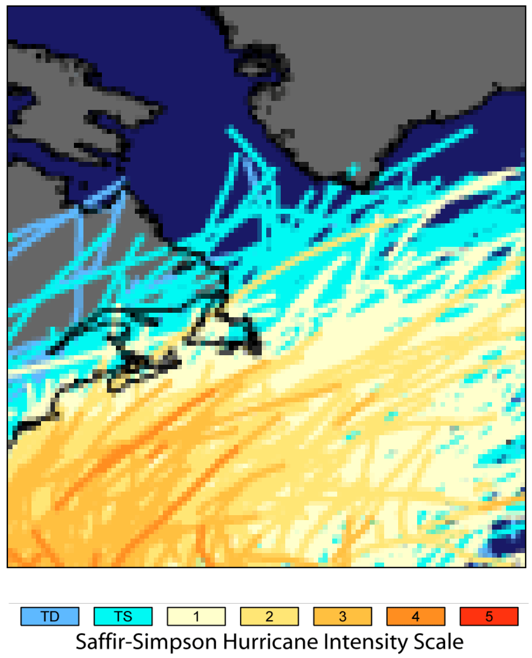


Figure 7 - Paths and Intensities of Tropical Storms Near Newfoundland

Source: Modified from (NASA - Earth Observatory)

Table 3 shows the range of wind strength and expected storm surge in each category of the Saffir-Simpson Hurricane Scale.

Table 3 - Saffir-Simpson Hurricane Wind Strength and Storm Surge

Hurricane Category	Sustained 1-min Wind Speed (m/s)	Expected Storm Surge (m above normal)
TS	< 33.4	< 1.2
1	33.4 to 42.7	1.2 to 1.5
2	43.2 to 48.9	1.8 to 2.4
3	49.4 to 58.1	2.7 to 3.7
4	58.6 to 68.9	4.0 to 5.5
5	> 69.5	> 5.5

Source: (NOAA - National Hurricane Center, A)

Figure 8 shows the number of tropical storms that have occurred in any Newfoundland marine area from 1901 to 2000 on a monthly basis. It indicates that September is the month most prone to tropical storms but that they have been known to occur anytime between June and November.

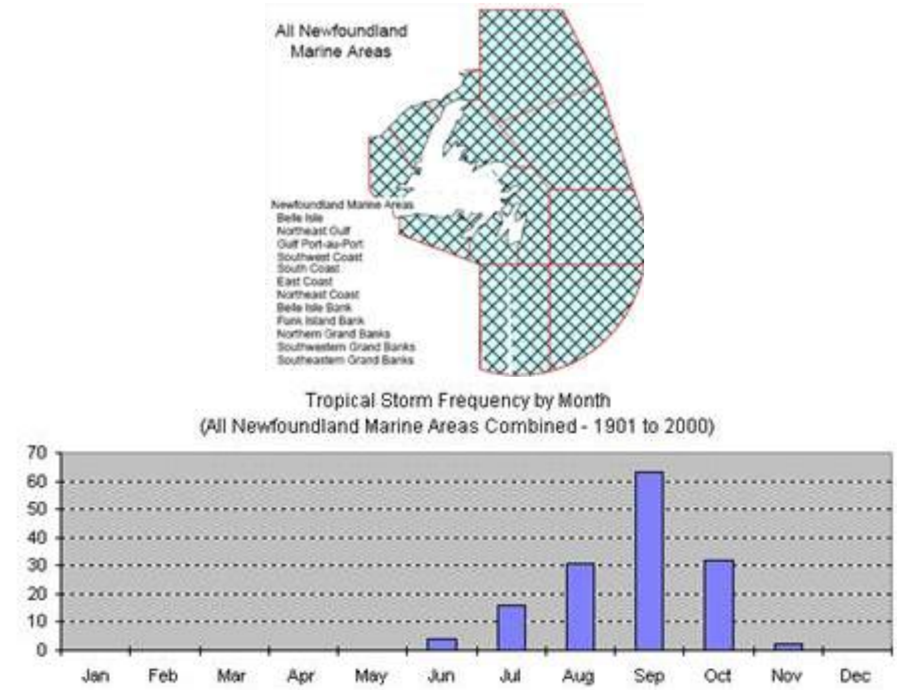


Figure 8 - Tropical Storm Count by Month in Newfoundland's Marine Areas (1901 to 2000)

Source: (Environment Canada)

2.3 Oceanography

This section discusses the major ocean currents, water properties, such as sea surface temperature and salinity, mean and extreme wave heights as well as the extent and concentration of sea-ice and icebergs that affect offshore Newfoundland.

2.3.1 Currents

The circulation in and around the Grand Banks is governed by the meeting of the Labrador Current and the North Atlantic Current along with the bathymetric features of the continental shelf.

The Labrador Current is a continuation of the Baffin Island Current and it flows southeast from roughly 60°N to the Grand Banks at roughly 43°N (Smith *et al*, 1937). It has a velocity of 30 to 50 cm/s along the edge of the continental shelf, with a transport of 4 to 8 Sv[1] (Reynaud *et al*, 1995; Greenberg and Petrie, 1988). The flow varies seasonally near the surface, having a range of 4 Sv, and has a minimum flow in March and April and maximum flow in October. Deeper flows remain relatively unaffected by seasonal change.

[1] A sverdrup (Sv) is equivalent to 1 000 000 m^3/s.

As the Labrador Current approaches the Grand Banks it divides into two streams. The inshore stream near the coast is approximately 100 kilometres wide and 150 metres deep and flows through the Avalon Channel. A stronger offshore stream over the shelf-break flows through the Flemish Pass, in a path 50 kilometres wide at a speed of 25 to 30 cm/s, and also around the eastern side of the Flemish Cap (Lazier and Wright, 1993; Petrie and Anderson, 1983).

The Gulf Stream departs the shelf-break near Cape Hatteras in the United States and flows northeast before it breaks into two branches. The northern branch consists of the bulk of the Gulf Stream's flow past the branch point and is known as the North Atlantic Current. It is roughly 300 kilometres wide and has a transport of 35 Sv having a maximum velocity of 100 cm/s (Krauss *et al*, 1987). The majority flows past the east side of the Flemish Cap before it turns east and follows the 50°N latitude line, while a varying amount of water is expelled from the current's eastern edge (Krauss *et al*, 1990; Krauss *et al*, 1987). It also contributes to, and receives water from, the Slope Current, south of the Grand banks, which closely follows the continental shelf and is a mix of water from the North Atlantic Current and coastal waters.

The North Atlantic Current and the Labrador Current, shown in Figure 9, typical converge and mix in an area southeast of the Grand Banks. The properties of the water on the Grand Banks region vary greatly from year to year and depend primarily on the strength and position of the North Atlantic Current. The Labrador Current brings relatively cold (< 4°C) water with low salinity (< 34 ‰) into the region of the three existing major offshore projects, whereas further offshore, the North Atlantic Current delivers warm (7 to 18°C), salty (> 35 ‰) water (White Rose, 2000).

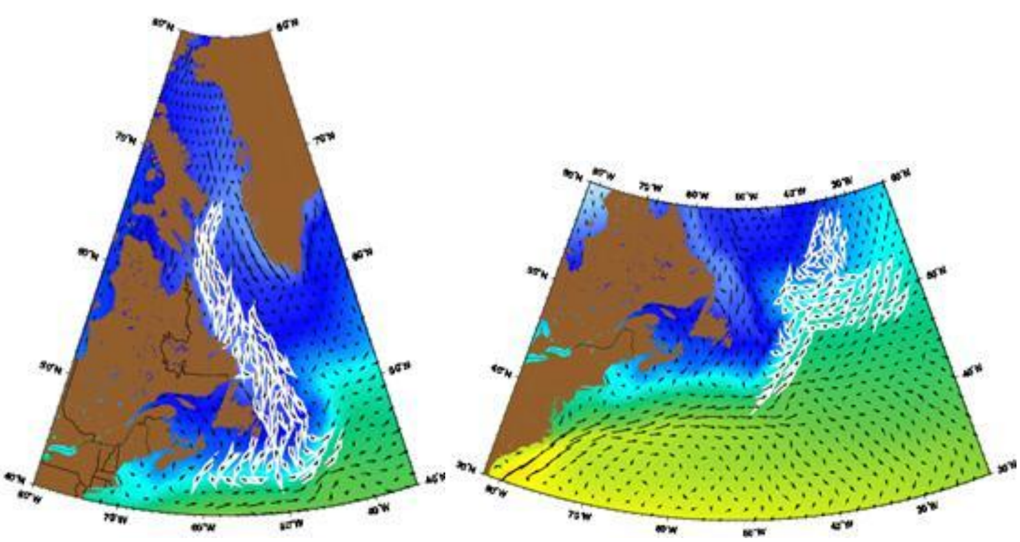


Figure 9 - Maps Highlighting the Labrador Current (left) and the North Atlantic Current (right)

Source: (MSVGA)

2.3.2 Sea Surface Temperatures

Figure 10 shows measured monthly maximum, mean and minimum sea surface temperatures near the White Rose oil field. For the few years of observation, the maximum sea surface temperature was 18.4°C in August and the minimum was near -1.8°C (below which the water would be frozen) in winter.

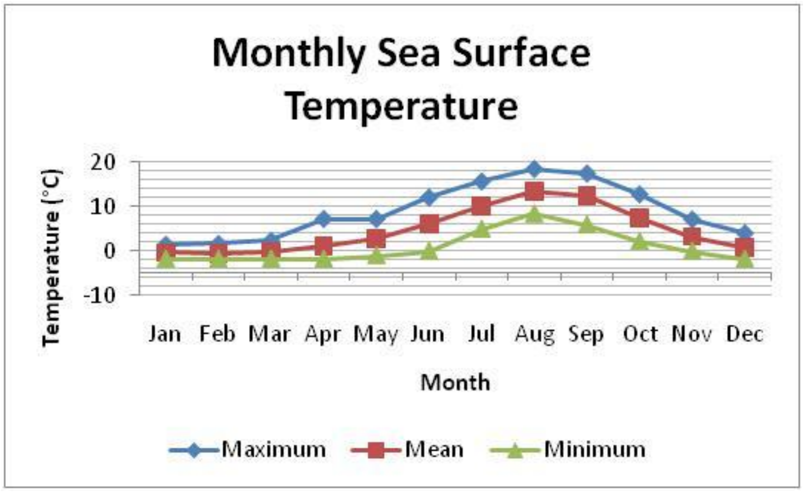


Figure 10 - Sea Surface Temperatures Near White Rose

Source: Modified from (White Rose, 2000)

The NOAA-NCEP Reanalysis data presented in Figure 11 is consistent with the above sea surface temperature means for the coldest (February) and warmest (August) months, respectively. Both the North Atlantic Current and the Labrador Current are apparent by examining the structure of the sea surface temperatures below. The North Atlantic Current is most apparent in February where there is a strong temperature gradient south of the Grand Banks and the effect of the Labrador Current is visible as the tongue of cold water extending down in a southeastward direction in August. The mean sea surface temperatures in the region of interest range from 0 to 5°C in February and 11 to 17°C in August.

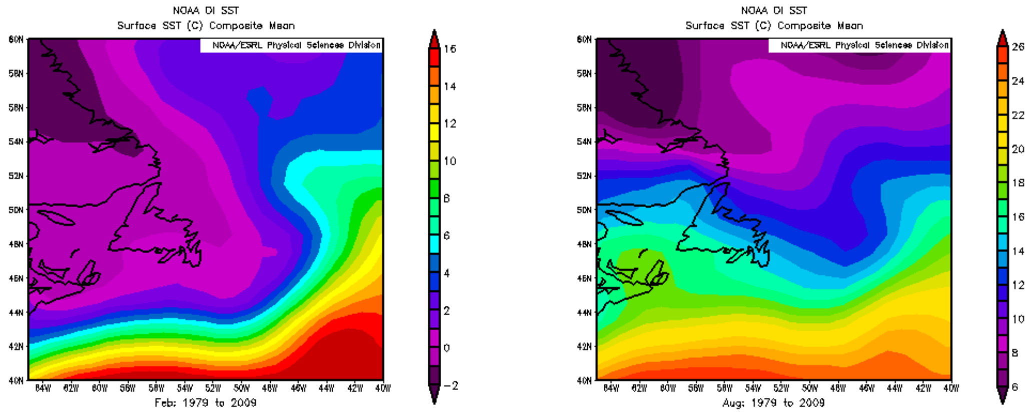


Figure 11 - Climatological Maps for Mean February (left) and August (right) Sea Surface Temperatures

Source: (NOAA OI SST)

2.3.3 Waves

Combined significant wave height is defined by the World Meteorological Association (WMO) as the average height, from trough to crest, of the highest 1/3 of individual waves typically observed for a period of 20 minutes. Table 4 shows the return periods for various significant wave heights and maximum wave heights for the location of White Rose (46.88 N, 48.33 W). Note that the maximum wave height is slightly less than twice the height of the significant wave height for each return period.

Table 4 - Significant and Maximum Wave Height Return Periods

Return Period (years)	Significant Wave Height (m)	Maximum Wave Height (m)
1	10.5	19.7
10	12.7	23.8
25	13.5	25.2
50	14.1	26.3
100	14.7	27.4

Source: AES40 available in (White Rose, 2000)

According to a global hindcast study for 1958 to 1997 (Cox and Swail, 2001), the mean annual significant wave height off the east coast of Newfoundland was 2 to 3 metres, while the 99th percentile annual significant wave height was 7 to 8 metres. These results appear consistent with those found in the AES40 hindcast of Table 4.

2.3.4 Sea-ice and Icebergs

Both sea-ice and icebergs occur nearly every year on the Grand Banks. Their extent and concentration varies spatially and temporally.

2.3.4.1 Sea-ice

Sea-ice concentration varies based on air temperature, sea state, surface winds, salinity, ocean temperature and various other factors. Figure 13 shows the observed climatological (1978 to 2008) sea-ice concentration for December through May offshore Newfoundland and Labrador. Sea-ice begins to approach the Grand Banks in January and can stay until May with maximum concentration usually occurring in February or March. Figure 12 shows the maximum sea-ice concentration from 1978 to 2008, which occurred in February of 2004.

The three major offshore projects are close to the southern limit of the regional ice pack where warm waters from the North Atlantic Current dissipate the last remnants of ice. The vast majority of ice that reaches the Grand Banks region is relatively soft first-year ice. Any second-year ice present would have to travel down from Baffin Island (near 70°N) (Markham, 1980).

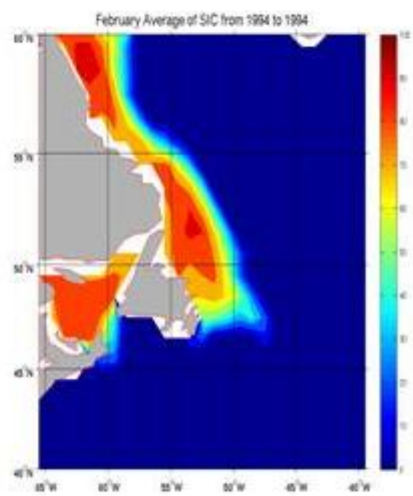


Figure 12 - Maximum Observed Sea-ice Concentration from 1978 to 2008 (February 1994)

Source: (HadISST) courtesy of Melissa Gervais

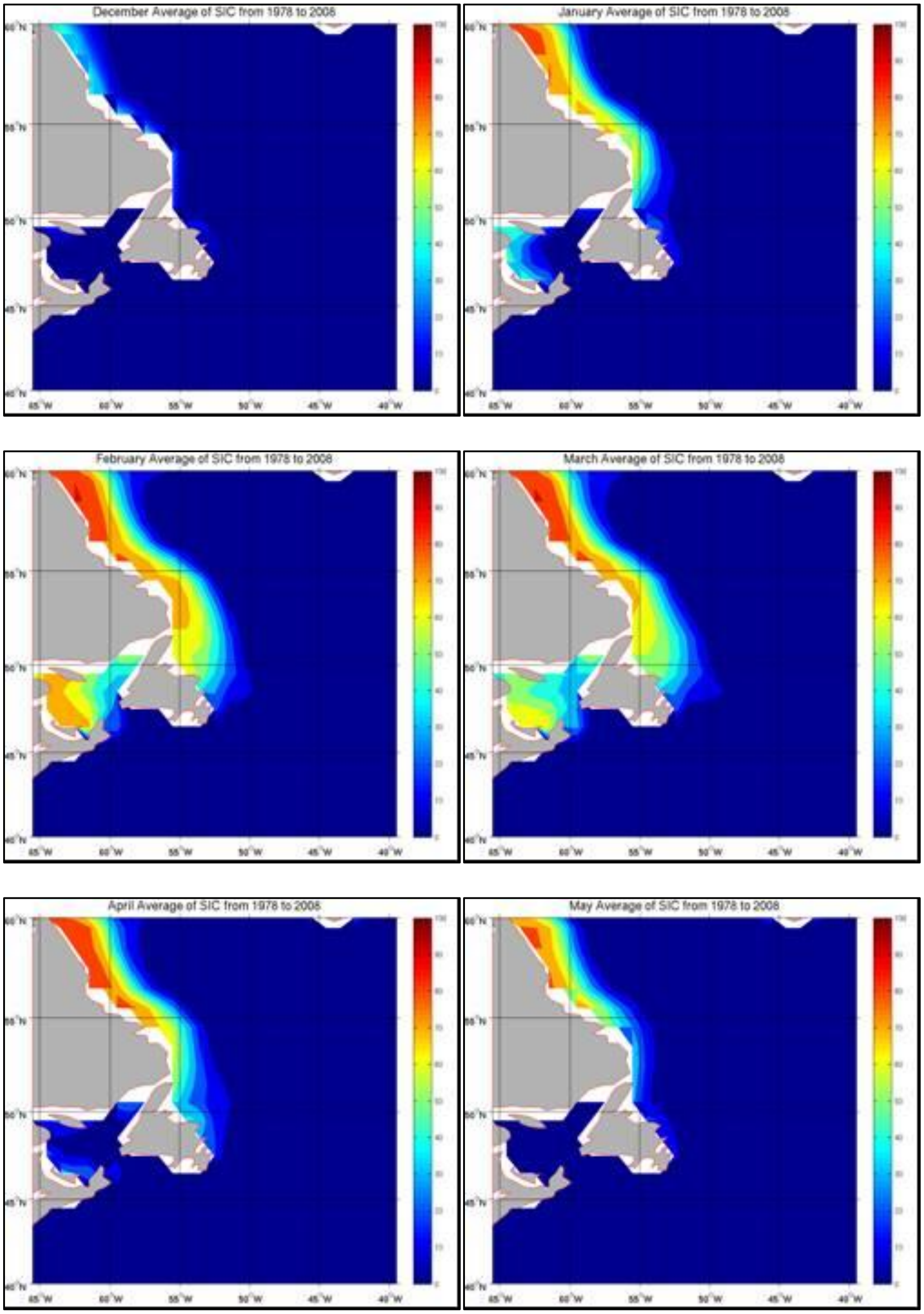


Figure 13 - Observed Climatological Sea-ice Concentration for December through May (1978 to 2008)

Source: (HadISST) courtesy of Melissa Gervais

2.3.4.2 Icebergs

Ninety-five percent of icebergs that reach Newfoundland each year are calved off glaciers in Greenland (85% from west Greenland and 10% from east Greenland), with the remaining 5% coming from Ellesmere Island. The number of icebergs that reach the Grand Banks is directly correlated to the extent of sea-ice in the Labrador Sea in winter and early Spring (Marko *et al*, 1994; Skinner, Lye, & Bruneau, 2010). The number reaching the Grand Banks varies from 0 (in 1966) to 2202 (in 1984) with an average of 900 (from 1990 to 2000) (IIP). The climatological extent of iceberg travel is shown in Figure 14.

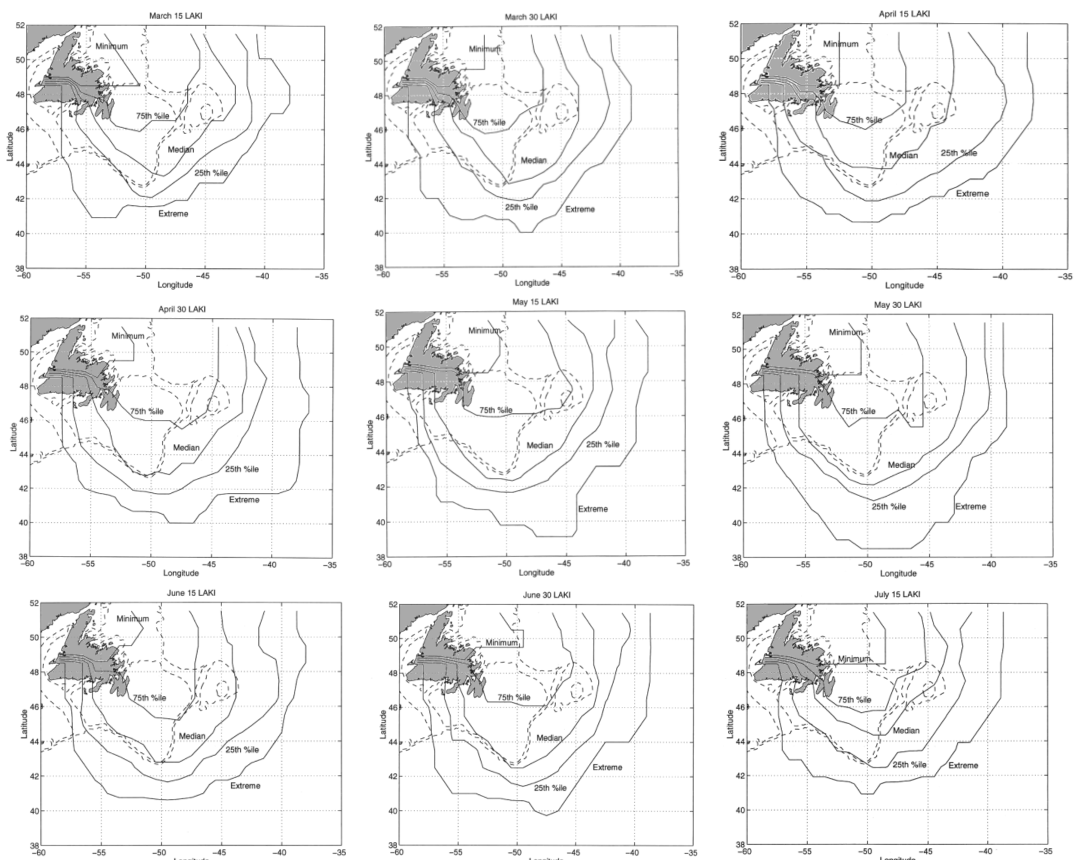


Figure 14 - Climatology of Iceberg Extent from March 15 to July 15 (1975 to 1995)

Source: (USCG - IIP)

Figure 15 shows the maximum and mean annual numbers of icebergs observed offshore Newfoundland from 1989 to 1999. Note that the count is higher where the Labrador Current flows strongly, such as the Avalon Channel and the Flemish Pass. Near the Grand Banks, icebergs tend to move independently of sea-ice, as sea-ice tends to be relatively weak in that region.

Typical icebergs have an average drift speed of 20 km/day on the Grand Banks and 30 km/day in deeper waters, but this can vary based on winds, currents and extent of pack ice.

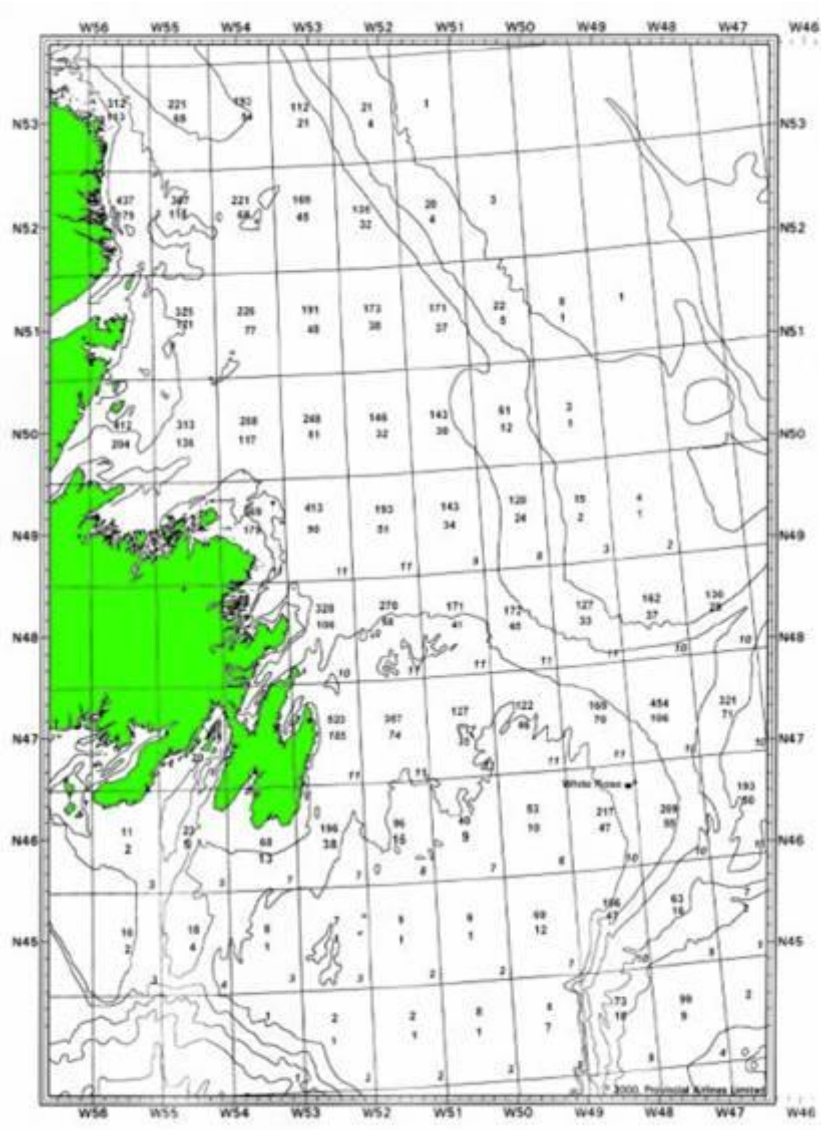


Figure 15 - Maximum and Mean Annual Numbers of Icebergs Observed Offshore Newfoundland

Source: PAL Iceberg Sighting Database 1989 - 1999, available from (White Rose, 2000)

2.4 Geology

This section discusses Newfoundland's offshore geological features such as coastal environment (including tides), surficial sediments and lithostratigraphy, and seismicity.

2.4.1 Coastal Environment

Rocky headlands and steep cliffs, and interdispersed pebble-gravel beaches and baymouth bars, characterize Newfoundland's eastern coast. The shoreline varies from deeply indented to relatively straight having few embayments (White Rose, 2000).

The shoreline can be classified into three categories: exposed systems; low to moderate-energy coves and; high-energy coves (Catto, 1994). An exposed system, such as Placentia Bay, consists of open coastline having primarily current driven sediment. The low to moderate and high-energy coves, which dominate the Southern Shore, have relatively stationary sediment, produced from cliffs and glacial till.

There are moderate tides along the coast, having normal tide heights of roughly 1 metre (White Rose, 2000).

2.4.2 Surficial Sediments and Lithostratigraphy

It is generally accepted that sea level was below the 110 metre isobath on the Grand Banks, roughly 15 000 years ago. As sea level rose, surficial sediments were reworked resulting in a 1 to 3 metre layer of sand and gravel on the sea floor (Fader and King, 1981; Stoffy-Egli*et al*, 1992).

Near the White Rose area, the sea floor consists of relatively hard packed fine to medium sand up to a depth of 3 metres known as the Adolphus Sand Formation (White Rose, 2000). This lies above the Grand Banks Drift, which is a layer of rough sand and gravel that lies 2 to 10 metres below the sea floor. The (Tertiary) Banquereau Formation (10 to 700 m) lies beneath the Grand Banks Drift and is characterized by clay and cobbles.

The lithostratigraphy of the Jeanne D'Arc Basin, in which the three current major offshore projects are located, is presented in Figure 16. It is apparent that the uppermost layers are dominated by sandstone and shale, whereas further down there is limestone intermingled.

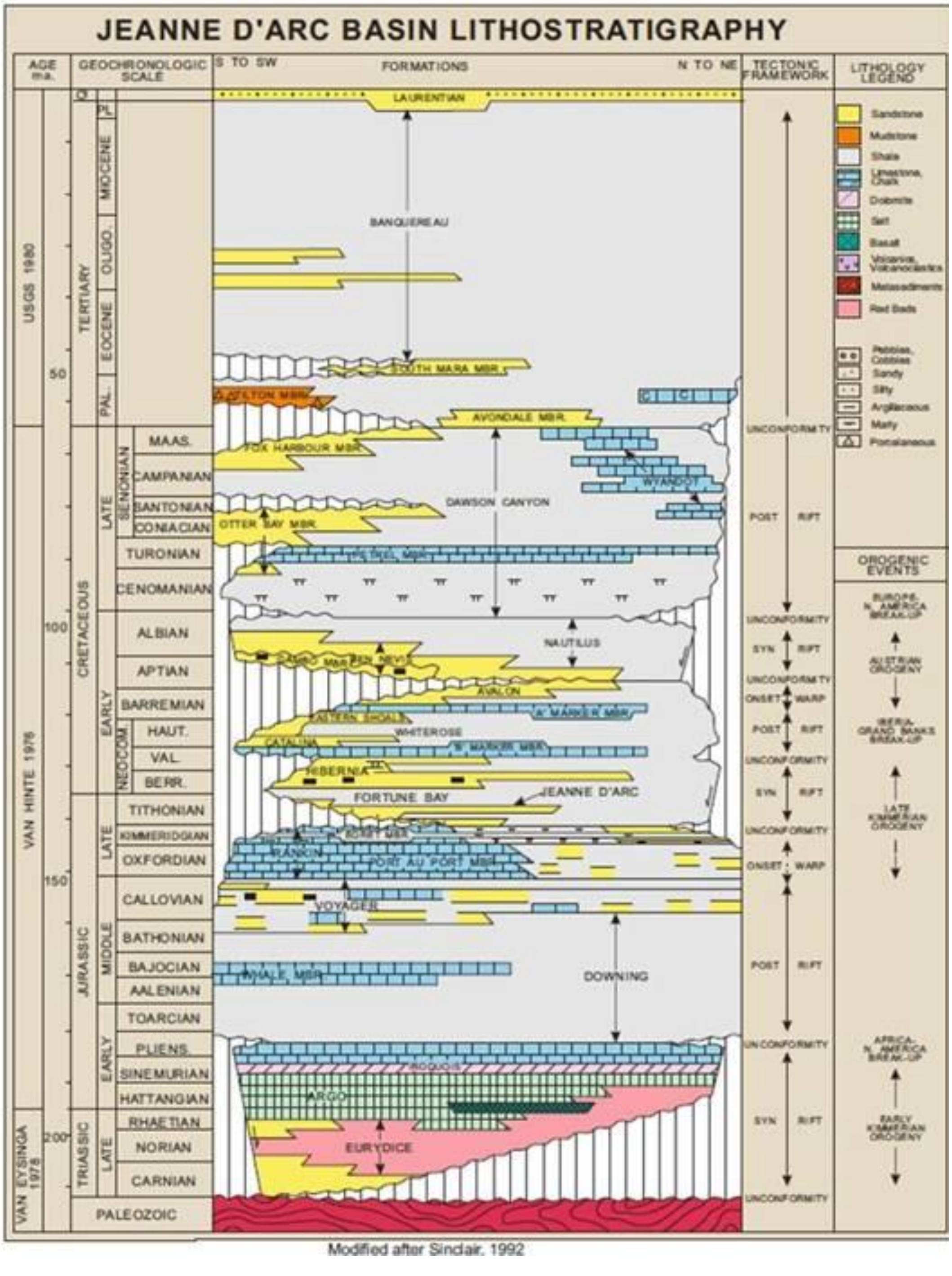


Figure 16 - Jeanne D'Arc Basin Lithostratigraphy

Source: (C-NLOPB - Maps)

2.4.3 Seismicity

Relatively weak seismic events (less than magnitude 5) are not well documented for offshore Newfoundland (Seaconsult, 1988; Adams, 1986).The largest earthquake on record was the 1929 magnitude 7.2 earthquake near the Laurentian Slope (roughly 650 kilometres southwest of White Rose) that caused the Burin Peninsula Tsunami. Three earthquakes with magnitudes near 6 were measured in the same region in 1951, 1954 and 1987 (Seaconsult, 1988). It is apparent from Figure 17, which shows all of the earthquakes on record in Canada, that while there have been several small earthquakes in Newfoundland's offshore region, those with a magnitude greater than 5 are few in number and concentrated on the Laurentian Slope.

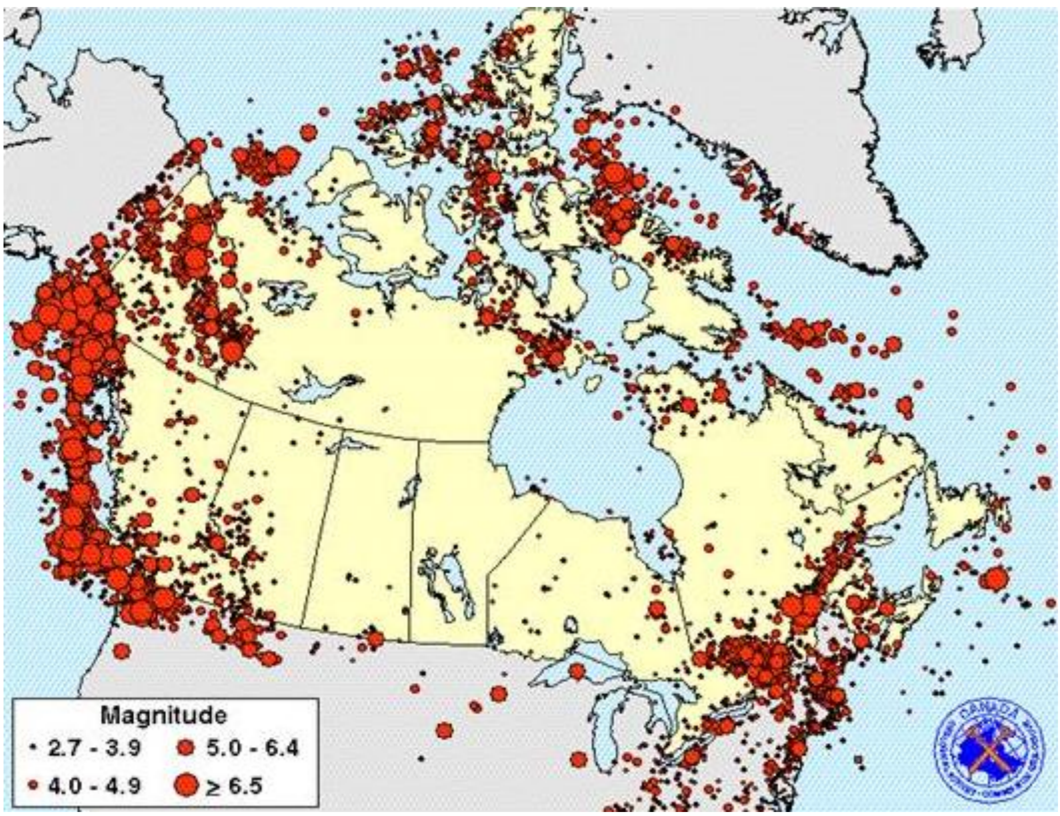


Figure 17 - Map of Earthquakes in Canada

Source: Modified from (NRCan - Earthquake Canada)

3.0 Physical Environment – Comparison of Comparable Jurisdictions

The previous section reviewed the climate, oceanography and geology of Newfoundland and Labrador. Similar detailed analyses are performed on the North Sea and Norwegian Sea (United Kingdom and Norway), the Gulf of Mexico (United States) and Australia. These reviews are provided in Appendix III. The following section looks at the comparison between the Newfoundland and Labrador offshore and the selected jurisdictions.

3.1 Geography

The offshore oil and gas operations in the North Sea, Norwegian Sea and the Gulf of Mexico are in a relatively small area compared to Australia. Newfoundland's current extraction and exploration operations are concentrated in an even smaller region.

3.1.1 Operating Depth

In all of the regions examined, the offshore oil and gas industry operates primarily on continental shelves up to depths of 200 metres. More recently, exploration has ventured out into deeper waters down the shelf slopes.

All of Newfoundland and Labrador's offshore oil platforms are located in the Jeanne D'Arc Basin, where waters are typically less than 200 metres deep, however Chevron Canada has just completed drilling Canada's deepest well in the Orphan Basin, 430 kilometres northeast of St. John's, at a depth of 2 600 metres.

Norway has operations, such as the Ormen Lange gas field, in depths ranging from 800 to 1 100 m, whereas their deepest discovery, the Gro gas field, is located in water just shy of 1 400 metres. Over half the active leases in the Gulf of Mexico are in water depths greater than 1 000 m, although only a fraction of the approved drilling applications and less than 1% of active platforms are at these depths. Wells as deep as 2 700 metres have been drilled in the Cheyenne field in the Gulf of Mexico. The Deepwater Horizon was drilling at a water depth of approximately 1 500 metres during its blowout. Australia has just recently issued drilling permits for waters as deep as 3 750 metres off of the Western Australian coast.

3.1.2 Isolation

The shores surrounding the North Sea and the Gulf of Mexico both have a relatively high population density, as is shown in Figure 18. Western Australia and Newfoundland have a much lower population density within the vicinity of offshore oil and gas operations. As a result of offshore operations being located farther from a large number of major population centres there is less infrastructure immediately available in Newfoundland and Australia than in the North Sea and Gulf of Mexico.

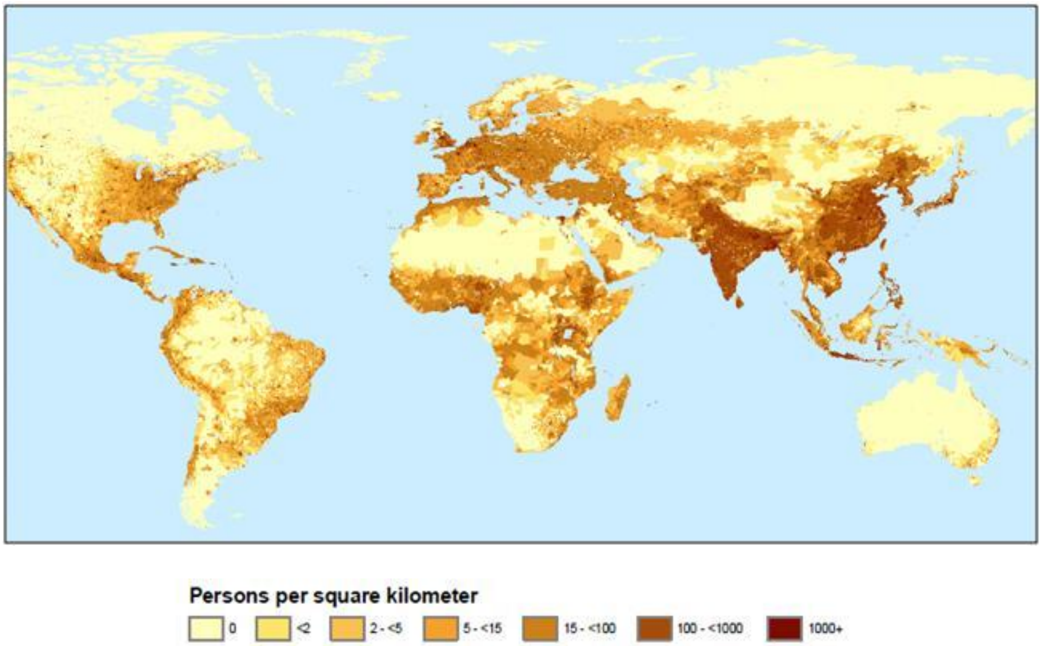


Figure 18 - World Population Density as of 2000

Source: Modified from (Columbia University - SEDAC)

3.2 Climate

The four regions examined encompass a wide variety of climates, from the tropical climate in northern Australia to the Gulf of Mexico's subtropical climate to the colder temperate climates in Newfoundland and the North Sea. This section discusses the particular differences between each region's climate.

3.2.1 Temperature

Newfoundland is the coldest of the regions examined, having the lowest cold season air temperature range offshore and lowest onshore average and record lows, as per Table 5. Its air temperature does resemble that of the North Sea in the warm season, but is always much cooler than the Gulf of Mexico and Australia.

Table 5 - Comparison of Surface Air Temperatures

Region	Onshore Temperature Climatology (°C)				Offshore Mean Temperature Range (°C)	
	Record T_{min}	Min $AvgT_{min}$	Max $AvgT_{max}$	Record T_{max}	Cold Season	Warm Season
Newfoundland	-29	-9	21	34	0 to -5	13 to 16
North Sea	-20	-7	22	38	-2 to 5	11 to 17
Gulf of Mexico	-15	7	34	42	13 to 18	27 to 29
Australia	-3	6	34	44	11 to 26	17 to 29

Source: (BBC World Weather; NOAA/NCEP Reanalysis Data)

3.2.2 Precipitation

On average, St. John's, Newfoundland experiences 14.8 wet days per month, with little variation throughout the year and a mean monthly precipitation of 114.4 mm. Regions surrounding the North Sea typically experience more wet days per month (except London, England) but with less mean precipitation (except for Bergen, Norway). New Orleans and Houston both have less mean wet days per month and whereas New Orleans has comparable mean monthly accumulation to St. John's, Houston has less. Melbourne, Australia has slightly less wet days per month on average but much less mean accumulated monthly precipitation. Darwin has comparable mean monthly precipitation and less mean wet days per month, but has great variability between seasons. Perth also has large seasonal variability but has much less mean monthly precipitation than Darwin and more mean wet days per month.

3.2.3 Fog and Visibility

The Grand Banks of Newfoundland experiences more than 90 foggy days per year, whereas the Placentia Bay area experiences more than 120 days of fog. Summer is the foggiest season in both regions.

The shores of the southern North Sea can experience 75 to 150 days per year of reduced visibility, which is defined as visibility less than 5 kilometres and is not necessarily due to fog. Foggy conditions persist about 2 to 5% of the time in the North Sea, with fog being most prevalent in the summer.

In the Gulf of Mexico there is heavy fog for more than 40 days per year, near the coast on the Texas-Louisiana border and they experience the most fog in winter. The shores of Australia's west and northwest coasts experiences less than 20 days of fog per year whereas some regions surrounding the Bass Strait experiences 40 to 60 days of fog per year.

3.2.4 Hours of Sunshine

Figure 19 shows the annual average number of sunshine hours per month. On average, Newfoundland, and the land surrounding the North Sea, experience roughly 40 hours per month. The Gulf of Mexico region experiences between 70 and 80 hours of sunshine per month whereas the northwestern Australia experiences around 90 hours per month and the southwest coast and Bass Strait region experience closer to 65 hours per month.

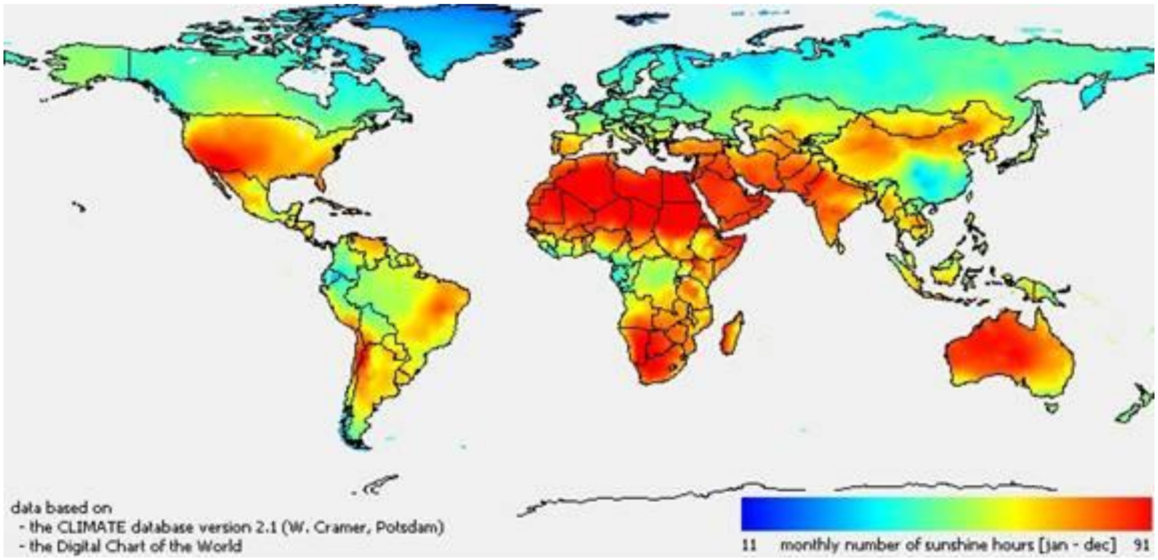


Figure 19 - Global Hours of Sunshine per Month

Source: (Rohan)

3.2.5 Wind

Offshore Newfoundland and the North Sea tie for the highest mean wind speed of the four regions, having a mean annual 6-hour wind speed of 9 to 10 m/s, as can be seen in Figure 20. The Gulf of Mexico's mean wind speed is 6 to 7 m/s whereas the mean wind speed in Australia ranges from 7 to 8 m/s in the south, to 4 to 5 m/s in the north.

In the run of a year, offshore Newfoundland can be expected to experience the highest sustained wind speeds of the four regions. Its 99th percentile annual 6-hour wind speed is 19 to 21 m/s whereas only a small range in the North Sea can make the same claim, as per Figure 21. The respective values for the Gulf of Mexico and Australia are 13 to 15 m/s and 9 to 19 m/s.

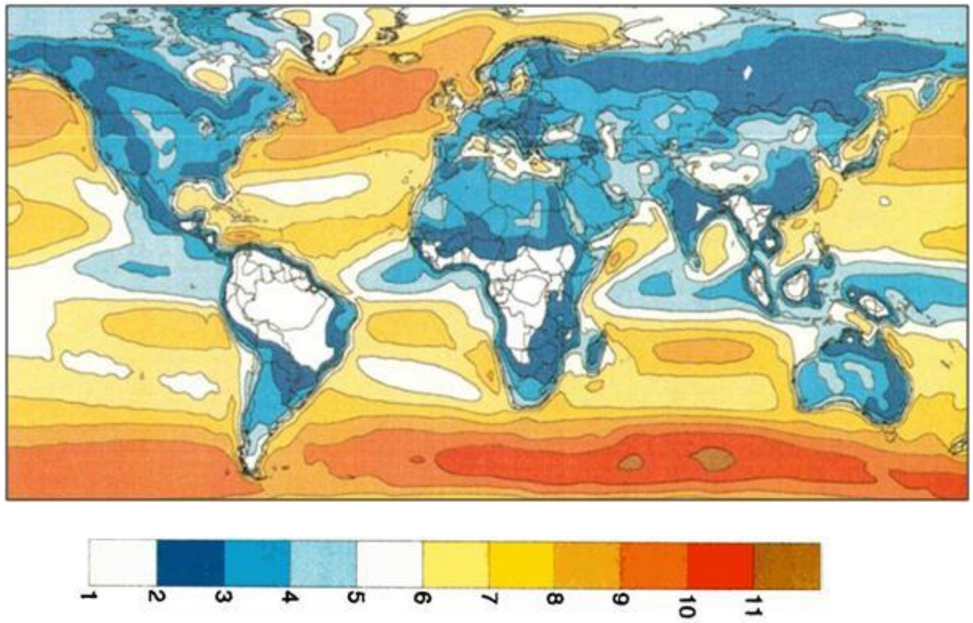


Figure 20 - Global Hindcast of Mean Annual 6-hour Wind Speed (m/s) (1958-1997

Source: Modified from (Cox and Swail, 2001)

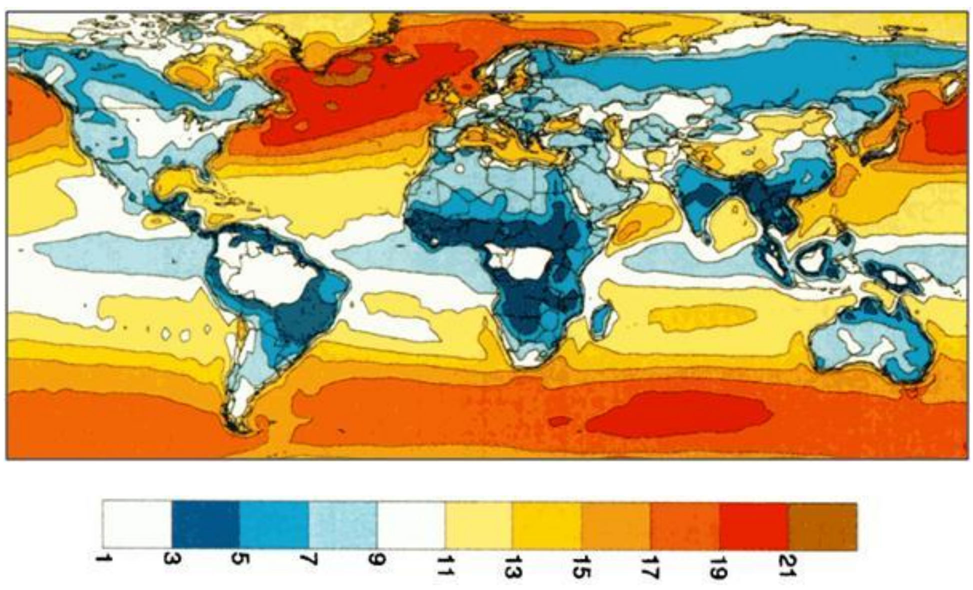


Figure 21 - Hindcast of 99th Percentile Annual 6-hour Wind Speed (m/s) from 1958-1997

Source: Modified from (Cox and Swail, 2001)

The 100-year 3-second gust offshore Newfoundland was calculated to be 43.6 m/s, whereas in the North Sea it was calculated to be between 46.7 to 51.3 m/s. In the Gulf of Mexico it is considered to be 57.8 m/s, whereas Australia has a 500-year maximum gust speed of over 80 m/s. Newfoundland and the North

Sea have noticeably smaller 100-year 3-second gust speeds than the Gulf of Mexico and Australia, due in large part to their much lower frequency of intense tropical storms. Intercomparison of these values should not be taken too seriously as each region uses a different method, based on different data sets, to calculate the wind speeds and their return periods. See each regions respective section on wind for further details.

3.2.6 Tropical Storms

Newfoundland's and the Gulf of Mexico's tropical storm season runs from June to November and peaks in September. Most tropical storms that reach Newfoundland are not of hurricane strength but storms up to category 2 are not uncommon. The Gulf of Mexico has the most tropical storm activity of all regions examined. They typically experience several tropical storms each year ranging up to category 5 hurricanes. The northwest coast of Australia can expect over two tropical storms per year, ranging up to category 5 hurricanes. The North Sea is under minimal threat from tropical storms. Figure 22 shows the paths and intensities of all tropical storms on record globally.

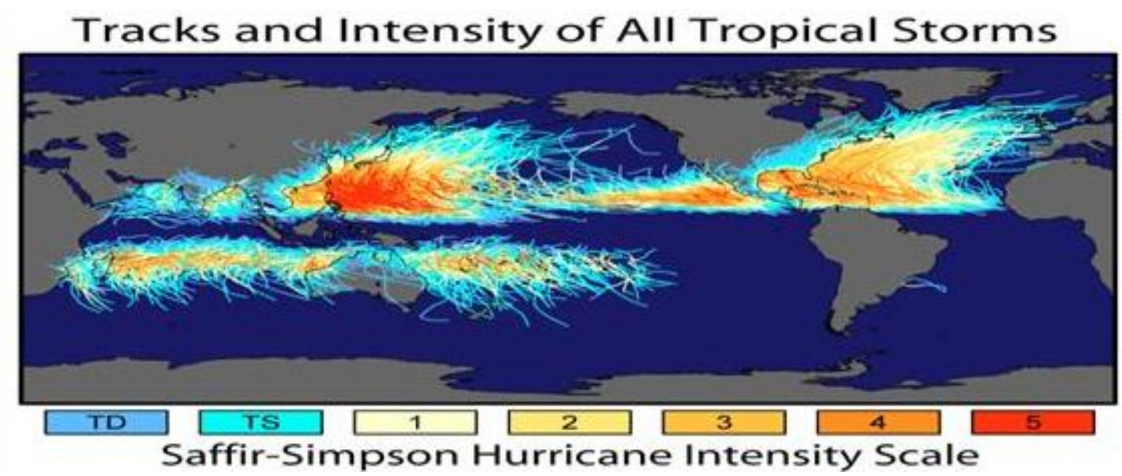


Figure 22 - Paths and Intensities of Tropical Storms Globally

Source: Modified from (NASA - Earth Observatory)

3.3 Oceanography

3.3.1 Currents

The currents offshore Newfoundland, including the Labrador Current and the North Atlantic Current, have surface speeds around 25 to 50 cm/s and 100 cm/s, respectively. The Slope Current and Norwegian Current near the North Sea have velocities of 10 to 30 cm/s and 10 to 100 cm/s, respectively. The Loop Current in the Gulf of Mexico has characteristic surface speeds near 80 cm/s, and can produce westward propagating eddies having velocities up to 6 cm/s (5 km/day). The Leeuwin Current (and its eddies), which runs southward down the coast of Western Australia, has a typical speed ranging from 50 to 100 cm/s and a maximum recorded surface speed of 180 cm/s. Characteristic currents in the Bass Strait have velocities around 30 cm/s but can be widely varying. All of the above mentioned current speeds vary throughout the year and on an inter-annual basis.

3.3.2 Sea Surface Temperatures

Newfoundland experiences the coldest sea surface temperatures in both the cold and warm seasons, as per Table 6. As with air temperatures, the North Sea is the only other region examined that has comparable values, and only in the warm season.

Table 6 - Comparison of Sea Surface Temperatures

Region	Cold Season Sea Surface Temperature Range (°C)	Warm Season Sea Surface Temperature Range (°C)
Newfoundland	-1 to 5	11 to 16
North Sea	5 to 8	13 to 18
Gulf of Mexico	17 to 21	29 to 30
Australia	12 to 27	17 to 30

Source: (NOAA OI SST)

3.3.3 Waves

Newfoundland experiences a similar mean annual significant wave height as the Bass Strait region of Australia, having values ranging from 2.5 to 3 m, as per Figure 23. The North Sea experiences 1.5 to 3 metres waves and the Gulf of Mexico experiences the smallest mean annual significant waves of 1 to 2 metres.

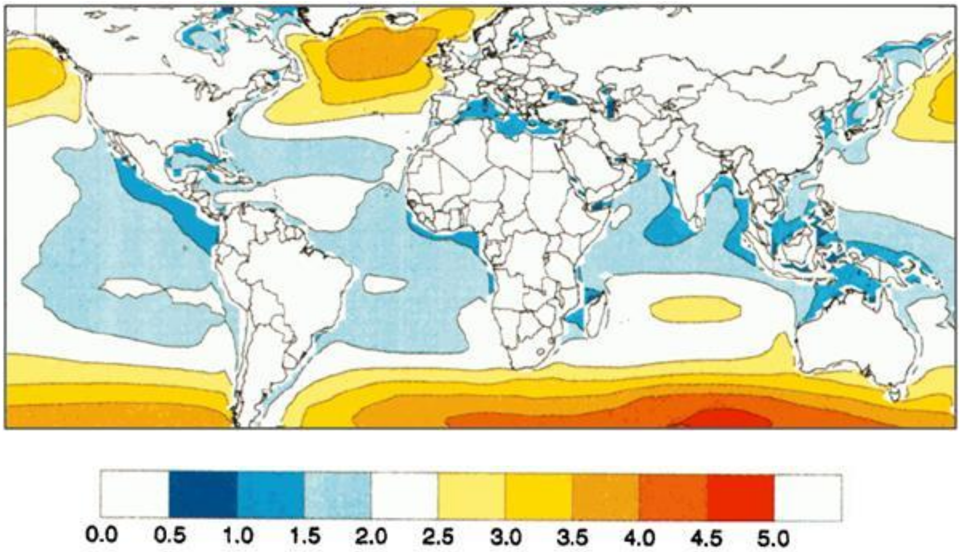


Figure 23 - Global Hindcast of Mean Annual Significant Wave Height (m) (1958-1997)

Source: Modified from (Cox and Swail, 2001)

Figure 24 shows that the 99th percentile annual significant wave height for offshore Newfoundland being 8 to 9 m, whereas the Norwegian Sea is similar. The North Sea experiences waves of 6 to 7 m, the Gulf of Mexico 3 to 5 m, whereas Australia experiences 6 to 7 metres waves in the south and 3 to 4 metres waves in the north.

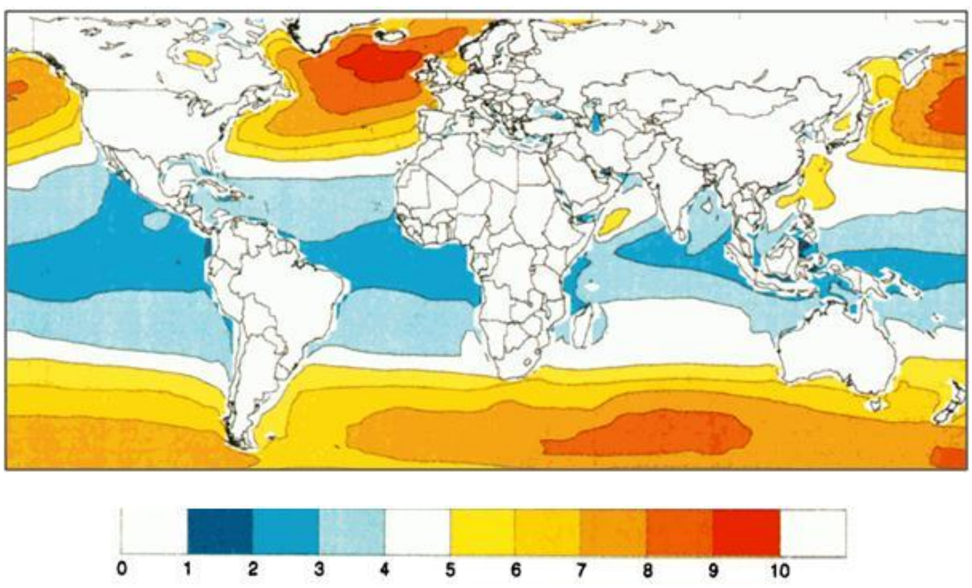


Figure 24 - Global Hindcast of 99th Percentile Annual Significant Wave Height (m) (1958-1997)

Source: (Cox and Swail, 2001)

The 50-year maximum wave height for Newfoundland is 26.3 metres whereas the North Sea's values range from 18 metres in the south to 32 metres north of the Shetland Islands. The Gulf of Mexico's 50-year maximum wave height is 22.8 metres.

Australia's northwest coast has a 100-year significant wave height of 13 m, which would be associated with tropical storms having a 30 kilometre radius. Newfoundland's 100-year significant wave height is 14.7 m, having a corresponding maximum wave height of 27.4 metres. The Bass Strait has a 100-year maximum wave height of 23 metres.

3.3.4 Sea-ice and Icebergs

Newfoundland is the only region of the four examined that experiences any sea-ice or icebergs.

3.4 Geology

Whereas this section compares characteristic coastal environments along with surficial sediments and stratigraphy, it is important to keep in mind that within each region there can be large local differences and the details discussed here should not be considered comprehensive.

3.4.1 Coastal Environments

The shoreline ranges from deeply indented to relatively straight. The Norwegian coast is dominated by fjords and archipelagoes in the north and less extreme terrain to the south. This is similar to the Scottish coast, which is less severe still. Estuaries and marshlands characterize the eastern English coast whereas the southern coasts of the North Sea are predominantly sandy. The Gulf of Mexico's shoreline varies from low-lying barrier islands to marshy areas and sandy beaches. Sandy beaches dominate Australia's coastline, whereas there are estuaries and deltas on the northwest coast and some cliff formations near the Bass Strait.

Newfoundland's coast experiences moderate tides having a range of about 1 metre. Spring tidal ranges are from 3 to 6 metres on the English and Scottish coasts of the North Sea and from 1 to 3 metres on the remaining North Sea coasts. The Gulf of Mexico's spring tidal range is less than 1 metre whereas its normal range is about half that. Australia's tidal ranges vary from less than a metre on the west coast to 12 metres on the northwest coast and 2 to 3 metres in the Bass Strait.

3.4.2 Surficial Sediments and Lithostratigraphy

The sea floor on the Grand Banks of Newfoundland is characterized by fine to medium sand on top of coarse sand and gravel. Huge pockets of mud and large expanses of sand along with various regions of gravel characterize the North Sea's sea floor. In the northern Gulf of Mexico, soft sediment from the

Mississippi River is prevalent in most regions with a progression to carbonate sediments toward southern Florida. Australia's northwest coast and Bass Strait have sediments dominated by carbonate and sand.

In the Jeanne D'Arc Basin offshore Newfoundland, the uppermost layers are dominated by sandstone and shale, whereas farther down there is limestone intermingled. Below the surfical sediments in the central and northern North Sea, there is sandstone in much of the upper layer, followed by mudstone and shale farther down. In the northern Gulf of Mexico, the upper layer is characterized by sandy continental sediments to the north and marine silts to the south. Farther down there is organic-rich shale and carbonates. In northwestern Australia, the Bonaparte Basin is dominated by limestone near the surface, then claystone and shale, followed by sandstone farther down. Near the Bass Strait in the Gippsland Basin, the uppermost layers are dominated by limestone whereas the lower layers range from marine to non-marine clastics.

3.4.3 Seismicity

Newfoundland, the North Sea and the Gulf of Mexico are all located in relatively weak to moderate seismic zones having only a handful of earthquakes above magnitude 5 measured in these regions. Australia's seismic activity is considered to be moderate to high compared to other intraplate regions, having magnitudes that can reach above magnitude 7. These earthquakes can lead to tsunamis. In Newfoundland, seismic activity is not particularity challenging.

3.5 Summary

The Newfoundland and Labrador offshore environment is the most challenging of the regions selected with respect to offshore exploration and production activities. A detailed review comparing the regions geography, climate, oceanography and geology reveals numerous facts which support this conclusion. These include, but are not limited to, the Newfoundland and Labrador offshore area having:

- the coldest temperatures of the regions examined;
- the most annual mean precipitation;
- the most foggy days per year;
- the least hours of sunshine per month (tied with the North Sea);
- the highest mean wind speed;
- the coldest sea surface temperatures;
- the largest annual significant wave heights (tied with The Norwegian Sea); and

- the only region with significant sea-ice and icebergs.

While all areas have their own unique challenges, this analysis indicates the Newfoundland and Labrador offshore region to be the most challenging of the regions under study. In particular, the presence of sea-ice and icebergs, in combination with high winds, cold temperatures and reduced visibility, contribute to a challenging environment in which special measures must be undertaken to ensure safe operation.

Review of Offshore Oil-spill Prevention and Remediation Requirements and Practices in Newfoundland and Labrador

December 2010

Appendix III

Physical Environment of Comparable Jurisdictions - the North Sea and Norwegian Sea, the Gulf of Mexico and Australia

Appendix III - Physical Environment of Comparable Jurisdictions

1.0 North Sea and Norwegian Sea (United Kingdom and Norway)

1.1 Introduction

The North Sea is predominantly part of the European continental shelf. It has a characteristic depth of 35 metres in the south, gently slopes down to depths of 90 metres farther north and finally to about 200 metres near the continental shelf edge (OSPAR, 2000). The Norwegian Trench, which is 20 to 30 kilometres wide and reaches depths of over 700 metres, is the North Sea's most significant bathymetric feature and parallels the Norwegian coastline from Oslo up past Bergen (Encyclopedia Britannica).

Oil and gas production is prevalent in most regions of the North Sea and along the continental shelf off the coast of Norway (henceforth referred to as the Norwegian Sea). Norway has operations, such as the Ormen Lange gas field, in depths ranging from 800 to 1 100 meters, whereas their deepest discovery, the Gro gas field, is located in water just shy of 1400 metres.

The entire coastline of the United Kingdom measures nearly 12 500 kilometres whereas Norway's coastline measures over 25 000 kilometres, including the mainland, fjords, minor indentations and numerous islands. Other coastlines bordering the North Sea include Belgium (66.5 kilometres), The Netherlands (451 kilometres), Germany (2 389 kilometres, including the shoreline east of Denmark) and Denmark (7 314 kilometres) (CIA World Fact Book).

Figure 1 shows the geography and bathymetry (500 metre intervals) of the North Sea and the Norwegian Sea.

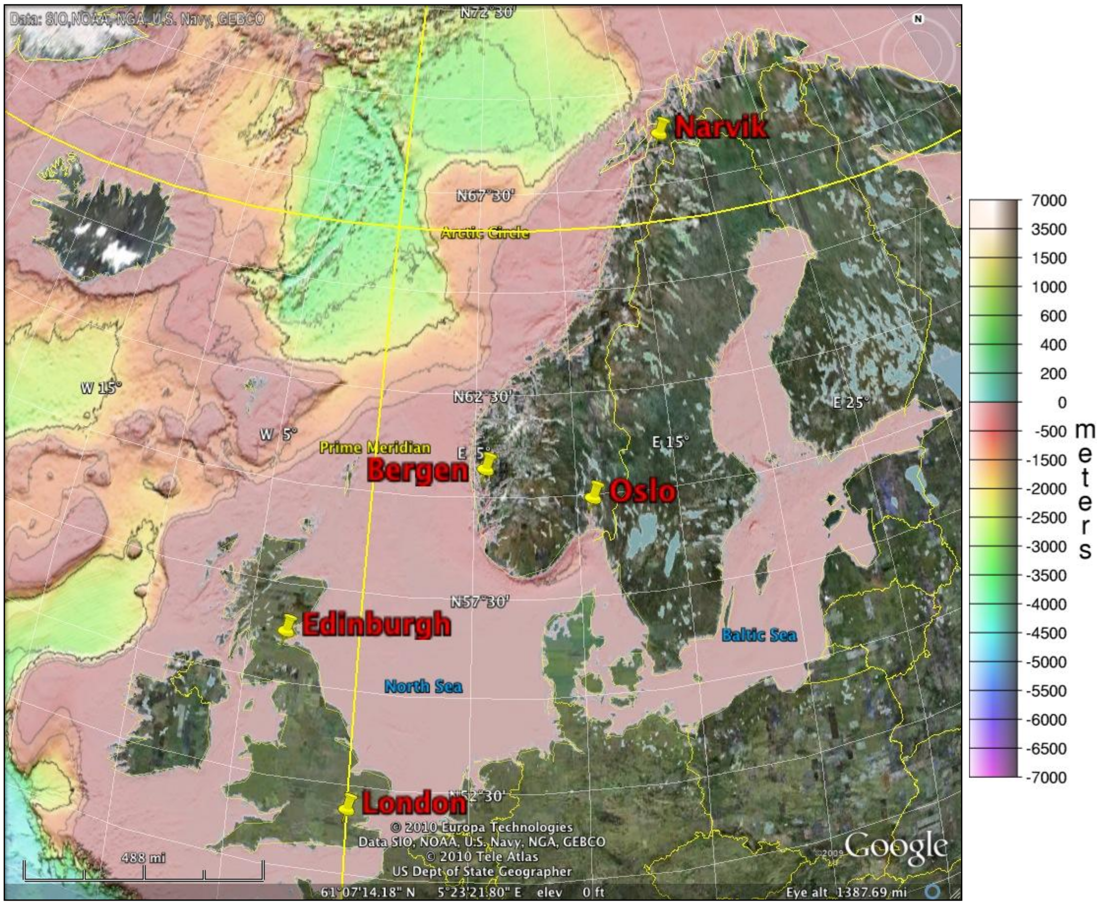


Figure 1 - Geography and Bathymetry (500 metre isobaths) of Northern Europe

Source: Google Earth using Global Topography V12.1

1.2 Climate

Partly as a result of the influence of the North Atlantic Oscillation, the North Sea is subject to large variations in wind direction and precipitation, particularly in the winter (Wallace and Gutzler, 1981). There is typically a high level of cloud cover (OSPAR, 2000).

The North Sea and Norwegian Sea are relatively warm in the winter, given the high latitudes. Strong currents carrying water from the Atlantic produce a temperate climate all year round.

This section discusses the North Sea's and Norwegian Sea's precipitation, mean and extreme surface air temperatures and wind speeds, as well as tropical storms.

1.2.1 Temperature

Tables 1 through 4 display climatological conditions for London and Edinburgh in the United Kingdom and Bergen and Narvik in Norway. London lies near the southern extreme of the North Sea, and has a record minimum temperature of -10°C, though the climatological minimum is closer to 2°C, and a record maximum temperature of 38°C, though the climatological maximum is near 22°C. Any oil platform located in the south of the North Sea would experience much more temperate extremes due to the moderating effects of the sea.

Farther north, on the coast of the Norwegian Sea and above the Arctic Circle, lies Narvik. Even at such a high latitude, the lowest recorded temperature is only -20°C, having climatological minimums around -7°C. For the warm season, record and climatological maximums are 30°C and 18°C respectively.

Table 1 - Climatological Conditions for London, England (51.51 N, 0.13 W)

Month	Temperature (°C)				Average Precipitation (mm)	Wet Days (>0.25 mm)
	Average		Record			
	Min	Max	Min	Max		
Jan	2	6	-10	14	54	15
Feb	2	7	-9	16	40	13
March	3	10	-8	21	37	11
April	6	13	-2	26	37	12
May	8	17	-1	30	46	12
June	12	20	5	33	45	11
July	14	22	7	34	57	12
Aug	13	21	6	38	59	11
Sept	11	19	3	30	49	13
Oct	8	14	-4	26	57	13
Nov	5	10	-5	19	64	15
Dec	4	7	-7	15	48	15

Source: (BBC World Weather)

Table 2 - Climatological Conditions for Edinburgh, Scotland (55.95 N, 3.16 W)

Month	Temperature (°C)				Average Precipitation (mm)	Wet Days (>0.25 mm)
	Average		Record			
	Min	Max	Min	Max		
Jan	1	6	-8	14	57	17
Feb	1	6	-9	14	39	15
March	2	8	-6	20	39	15
April	4	11	-4	22	39	14
May	6	14	-1	24	54	14
June	9	17	3	28	47	15
July	11	18	6	28	83	17
Aug	11	18	4	28	77	16
Sept	9	16	1	25	57	16
Oct	7	12	-2	20	65	17
Nov	4	9	-4	19	62	17
Dec	2	7	-7	14	57	18

Source: (BBC World Weather)

Table 3 - Climatological Conditions for Bergen, Norway (60.38 N, 5.33 E)

Month	Temperature (°C)				Average Precipitation (mm)	Wet Days (>0.25 mm)
	Average		Record			
	Min	Max	Min	Max		
Jan	-1	3	-14	13	143	20
Feb	-1	3	-11	11	142	17
March	0	6	-10	20	109	16
April	3	9	-6	22	139	19
May	7	14	-2	27	83	15
June	10	16	1	32	126	17
July	12	19	5	31	142	20
Aug	12	19	4	30	168	20
`Sept	10	15	1	26	228	21
Oct	6	11	-3	20	235	23
Nov	3	8	-6	15	211	21
Dec	1	5	-8	16	204	22

Source: (BBC World Weather)

Table 4 - Climatological Conditions for Narvik, Norway (68.42 N, 17.55 E)

Month	Temperature (°C)				Average Precipitation (mm)	Wet Days (>0.25 mm)
	Average		Record			
	Min	Max	Min	Max		
Jan	-7	-2	-20	9	55	15
Feb	-7	-2	-19	9	47	15
March	-5	1	-18	11	61	17
April	-2	5	-13	16	45	15
May	3	9	-7	24	44	17
June	7	14	-1	29	65	17
July	11	18	4	30	58	16
Aug	10	16	2	27	84	19
Sept	6	12	-3	23	97	20
Oct	2	6	-9	16	86	20
Nov	-2	3	-13	13	59	15
Dec	-5	-1	-19	11	57	16

Source: (BBC World Weather)

Figure 2 shows maps of the climatological (1979 to 2009) mean surface air temperature for February and August. The offshore surface air temperatures in the North and Norwegian Seas range from 0 to 6°C in February and from 10 to 16°C in August, with the North Sea on the warmer end of the scale. The values show good agreement with the range of temperatures shown in Table 1 to Table 4 above and give an idea of the spatial variability of air temperature within the region.

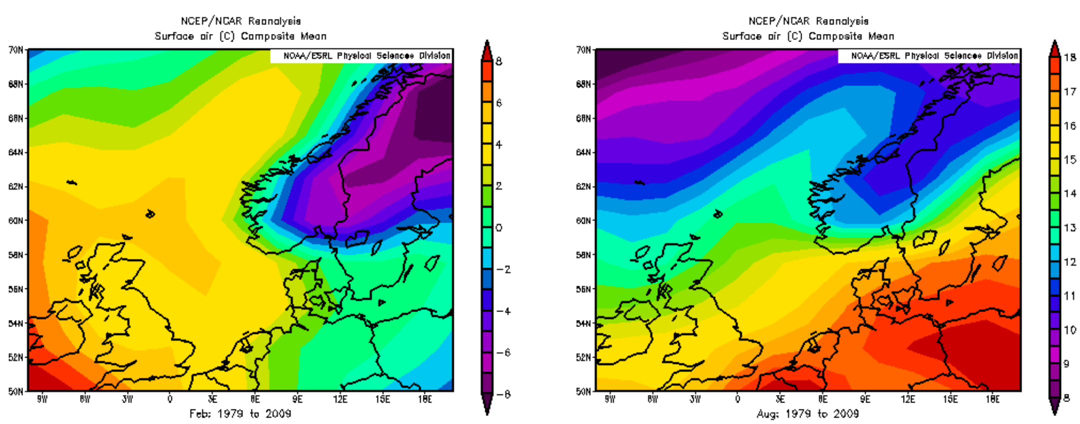


Figure 2 - Climatological Maps for Mean February (left) and August (right) Surface Air Temperatures in the North Sea and Norwegian Sea

Source: (NOAA/NCEP Reanalysis Data)

1.2.2 Precipitation

Bergen, located on the southwest coast of Norway, has by far the most precipitation of the four locations listed, having an average of 160.8 mm and 19.3 wet days (days receiving more than 0.25 mm) per month, shown in Table 3 above. This is due in large part to the predominant westerly flow over the North Sea and the upsloping that occurs on the steep Norwegian coast. London lies at the opposite extreme having an average of 49.4 mm and 12.8 wet days per month. Figure 3 shows the mean daily precipitation rate for February and August in the North Sea.

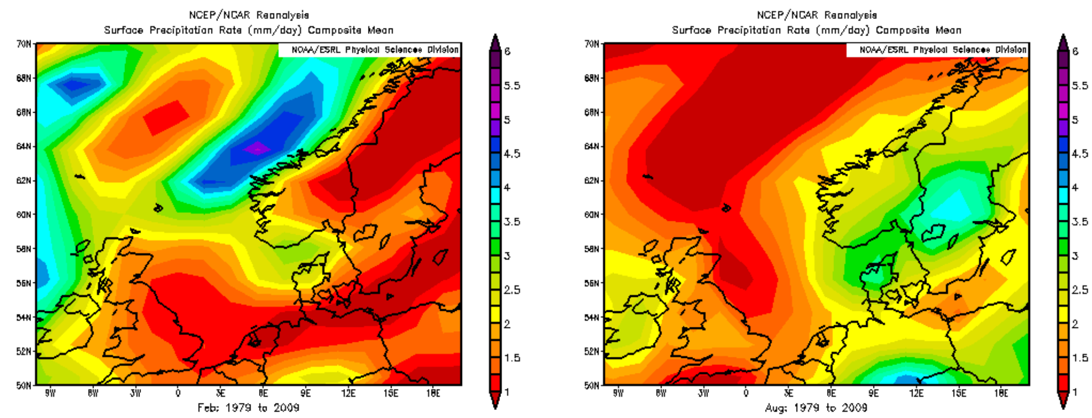


Figure 3 - Climatological Maps for Mean February (left) and August (right) Daily Precipitation Rates in the North Sea and Norwegian Sea

Source: (NOAA/NCEP Reanalysis Data)

1.2.3 Visibility

The North Sea fog, known as the Haar, is most common between April and September and is predominant near the east coast of Scotland and the Northern Isles (BBC Weather Centre). Figure 4 below shows the frequency of fog in January and July in the southern North Sea. The northern Norwegian coast experiences relatively high frequencies of fog in the summer, due to the frequent warm föhn winds that come down from the mountains and rush over the cool seas.

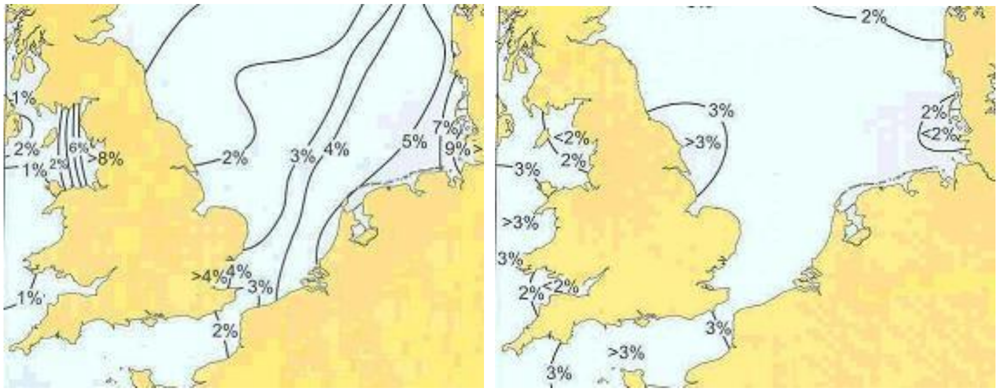


Figure 4 - The Frequency of Fog in the North Sea in January (left) and July (right)

Source: (The Weather Window)

According to Figure 5, much of the coast surrounding the southern North Sea experiences 75 to 150 days per year having low visibility (less than 5 kilometres). This is due to all sources of reduced visibility and not just fog.

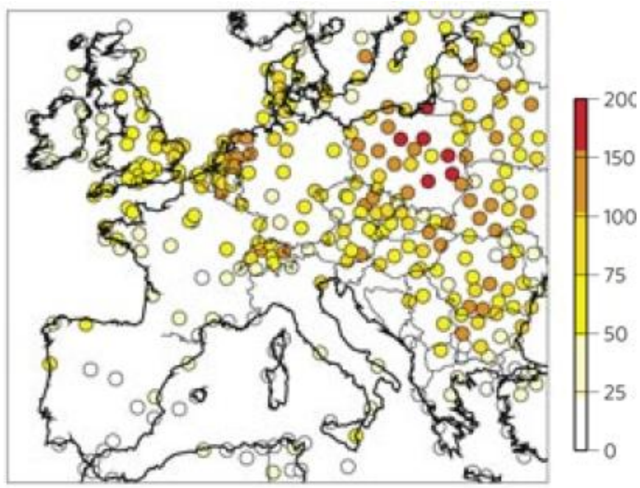


Figure 5 - Number of Days with Visibility less than 5 kilometres in Europe

Source: (Vautard *et al*, 2009)

1.2.4 Wind

Figure 6 shows maps of the mean surface wind speed for February and August, respectively. As is typical of mid-latitude locations, the winds are stronger throughout the region in the winter than in the summer. In February, the mean surface wind speed over the North Sea and Norwegian Sea is around 10 m/s, with winds weakening as you approach the coastlines. In August, the mean wind speed drops to between 5.5

and 7.0 m/s in most offshore regions, with local maxima occurring in the southeast North Sea and the western Norwegian Sea.

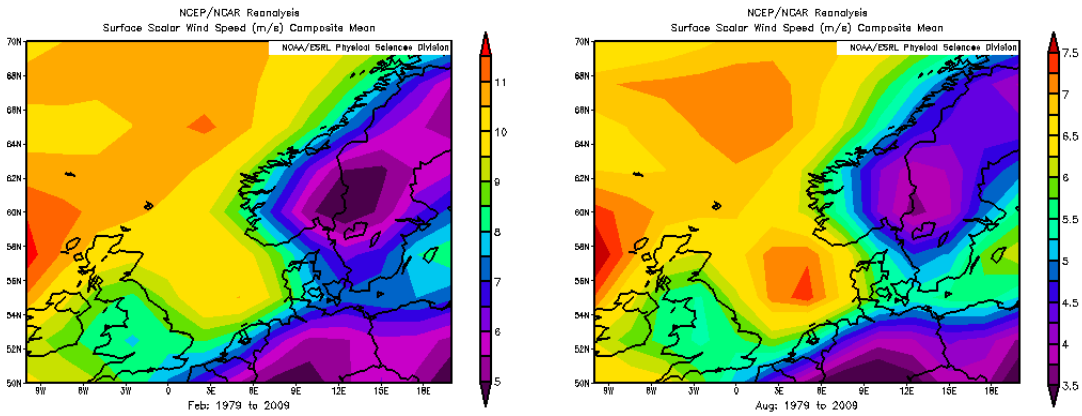


Figure 6 - Climatological Maps for Mean February (left) and August (right) Surface Wind Speeds in the North Sea and Norwegian Sea

Source: (NOAA/NCEP Reanalysis Data)

Table 5 shows a range of 1-hour mean and 3-second gust wind speeds for Bell Rock and Sumburgh, respectively determined by (Dukes and Palutikof, 1995). Bell Rock is located on an island 19 kilometres offshore, near Dundee, Scotland and Sumbrugh is located on the southern tip of the Shetland Islands, northeast of Scotland and therefore can be considered conservative extreme wind values of the North Sea due to their proximity to land. The range of values for each return period is due to the different analysis techniques used in the study.

Table 5 - Extreme Wind Speed Return Periods for Offshore Scotland

Location	**Return Period (years)**			
	10	**50**	**100**	**1000**
Bell Rock (1-hour mean speed m/s)	28.4 to 28.8	30.0 to 31.8	30.7 to 33.0	33.0 to 36.2
Sumburgh (3-sec gust speed m/s)	44.4 to 45.2	46.0 to 49.4	46.7 to 51.3	49.1 to 57.2

Source: (Dukes and Palutikof, 1995)

The highest recorded gust speed for low-level sites in the United Kingdom was 63.3 m/s on February 13, 1989. It was measured in Fraserburgh, on the northeast coast of Scotland (Met Office) and gives a good indication of how strong winds can get in the North Sea.

According to a global hindcast study for 1958 to 1997 (Cox and Swail, 2001), the mean annual 6-hour wind speed for the North Sea and coastal Norwegian Sea was 8 to 9 m/s, whereas the 99th percentile annual 6-hour wind speed was 17 to 21 m/s, with values decreasing toward the coast.

1.2.5 Tropical Storms

Whereas it is uncommon for a hurricane to survive the journey across the Atlantic Ocean, it does happen from time to time. The paths and intensities of tropical storms near northern Europe, shown in Figure 7, indicate that the British Isles tend to block most tropical storms from entering the North Sea, although some have been known to pass north into the Norwegian Sea. No tropical storm of hurricane strength (sustained 1-min wind speed greater than 34 m/s) has ever passed into the region.

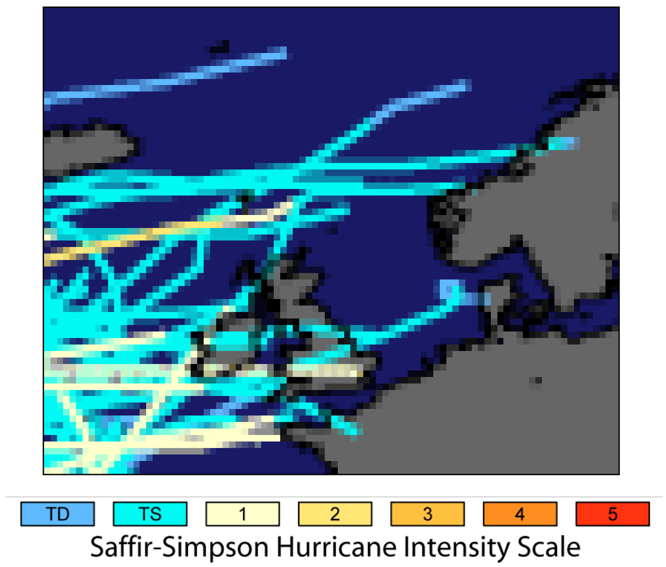


Figure 7 - Paths and Intensities of Tropical Storms Near Northern Europe

Source: Modified from (NASA – Earth Observatory)

1.3 Oceanography

This section discusses the major ocean currents, water properties, such as sea-surface temperature and salinity, along with mean and extreme wave heights that affect the North and Norwegian Seas.

1.3.1 Currents

Currents within the North Sea are primarily a combination of various streams of inflowing Atlantic water, the most important of which is the Slope Current (i.e., Shelf Edge Current), and the outflowing Norwegian Current (Mork, 1981), shown in Figure 8.

The Slope Current roughly follows the 500-metre isobath north-northwest along the eastern coast of the British Isles. It has a typical speed of 10 cm/s and transport of 1 to 2 Sv but can reach maximum speeds of 20 to 30 cm/s and transports of 4 to 7 Sv near the Faroe-Shetland Channel (Huthnance, 1986, Burrows and Thorpe, 1999). In the winter, the flow has uniform speed down to approximately 350 metres below the surface while in the summer the maximum speed occurs at roughly 200 metres (Souza *et al*, 2001). Many studies suggest that it carries much of the heat that enters the Nordic Seas (Sherwin *et al*, 1999).

The Norwegian Current runs north-northwest, to a depth of 50 to 100 metres, roughly following the isobaths off the coast of Norway (Haugan *et al*, 1991, Ikeda *et al*, 1989). There is a very broad range of velocity estimates having values measured at a 25 metre depth of 5 to 60 cm/s (Haugan *et al*, 1991) whereas other measurements varied from 10 to 40 cm/s, up to a maximum of 100 cm/s in June (Danielssen *et al*, 1997). It follows the Norwegian Trench, the deepest part of the North Sea, and branches into two at approximately 63.5 N with the majority of water following the inner branch along a narrow 20 to 30 kilometres wide path (Saetre, 1999).

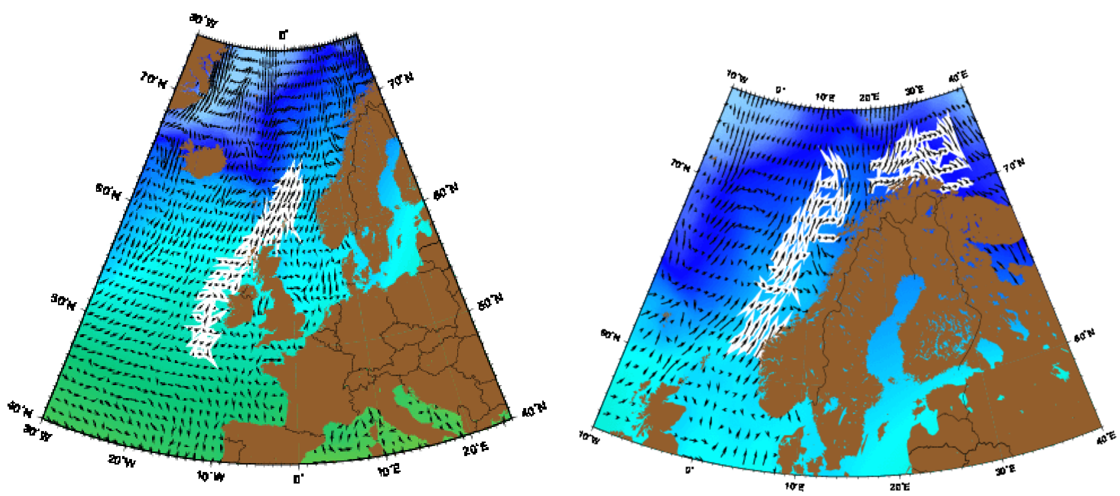


Figure 8 - Maps Highlighting the Slope Current (left) and the Norwegian Current (right)

Source: [MGSVA]

Figure 9 is a schematic of the various currents within the North Sea itself. Note the concentration of strong flows around the Norwegian Trench.

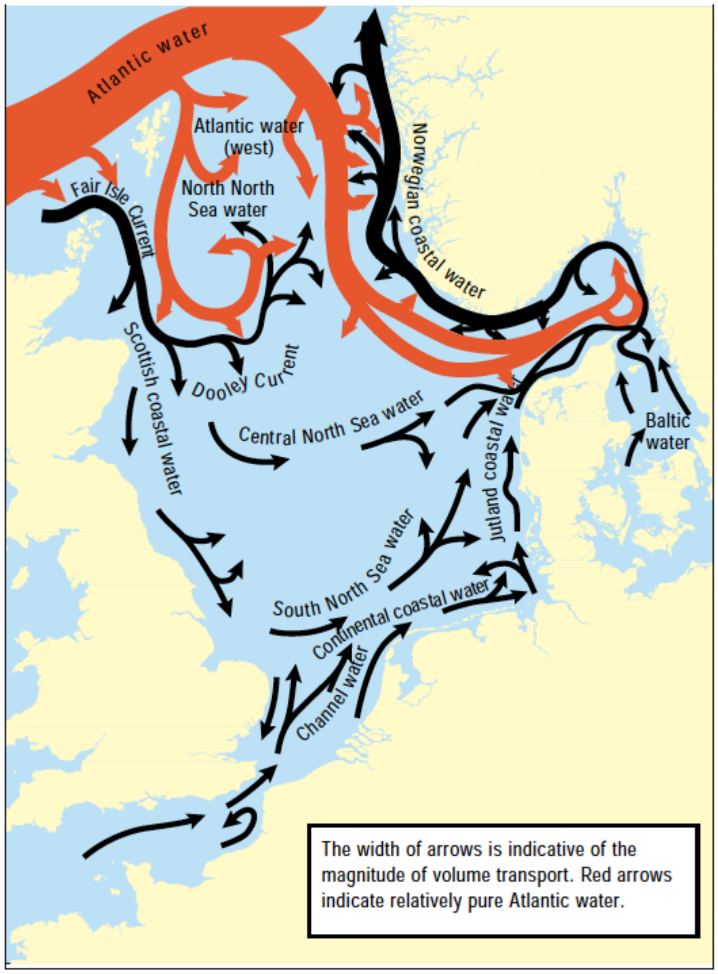


Figure 9 - Schematic of Currents within the North Sea

Source: (OSPAR 2000) modified from (Turrell at al, 1992)

A summary of the characteristic salinity and temperature for various flows in and around the North Sea can be found in Table 6. Water masses having low salinity are primarily located east of the North Sea in the waters between Norway, Denmark and Sweden. These waters are also subject to the largest temperature variability due to their distance from the moderating effects of the Atlantic water.

Table 6 - Typical Properties of water masses in the North Sea

Water Mass	Salinity	Temperature (°C)
Atlantic water	> 35	7 – 15
Atlantic water (deep)	> 35	5.5 – 7.5
Channel water	> 35	6 – 18
Baltic water	8.5 – 10	0 – 20
Northern North Sea water	34.9 – 35.3	6 – 16
Central North Sea water	34.75 – 35.0	5 – 10
Southern North Sea water	34 – 34.75	4 – 14
Scottish coastal water	33 – 34.5	5 – 15
Continental coastal water	31 – 34	0 – 20
Norwegian coastal water	32 – 34.5	3 – 18
Skagerrak water	32 – 35	3 – 17
Skagerrak coastal water	25 – 32	0 – 20
Kattegat surface water	15 – 25	0 – 20
Kattegat deep water	32 - 35	4 - 15

Source: (OSPAR, 2000) modified from (NSTF, 1993)

1.3.2 Sea-surface Temperatures

Figure 10 shows maps of the climatological (1979 to 2009) mean sea-surface temperature[1] for February and August. The moderating effects of the Atlantic are apparent from these figures, as a warm tongue of water is visible extending up the coast of Norway in February. The mean climatological sea-surface temperatures in the North and Norwegian Seas range from 5 to 8°C in February and from 12 to 18°C in August.

[1] Values for sea-surface temperature that appear over land should be ignored, as they are an artifact of the interpolation and smoothing of the analysis procedure.

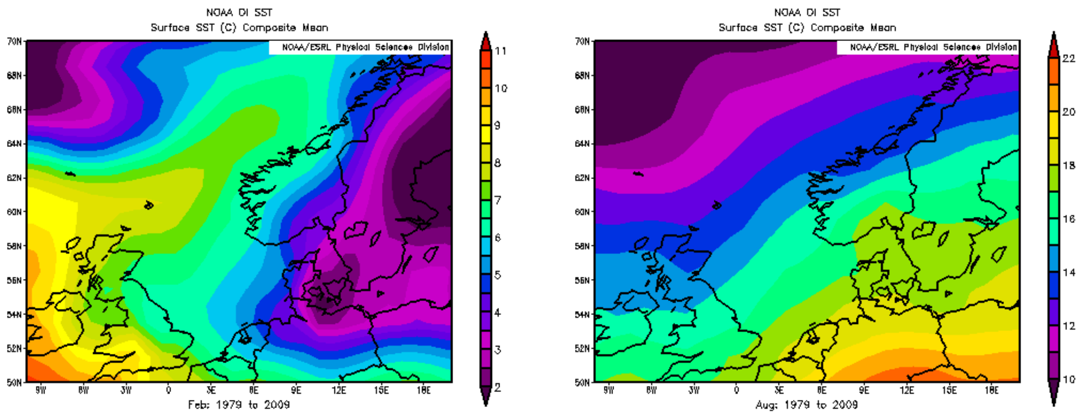


Figure 10 - Climatological Maps for Mean February (left) and August (right) Sea-surface Temperatures in the North Sea and Norwegian Sea

Source: (NOAA OI SST)

A more detailed look at the maxima, minima and annual mean of the North Sea's sea-surface temperatures can be found in Figure 11. In the cold season, the sea-surface can reach temperatures from 0 to 5°C whereas in the warm season they extend from 15 to 21°C. The amplitude of the seasonal temperature variation is lowest near Atlantic waters.

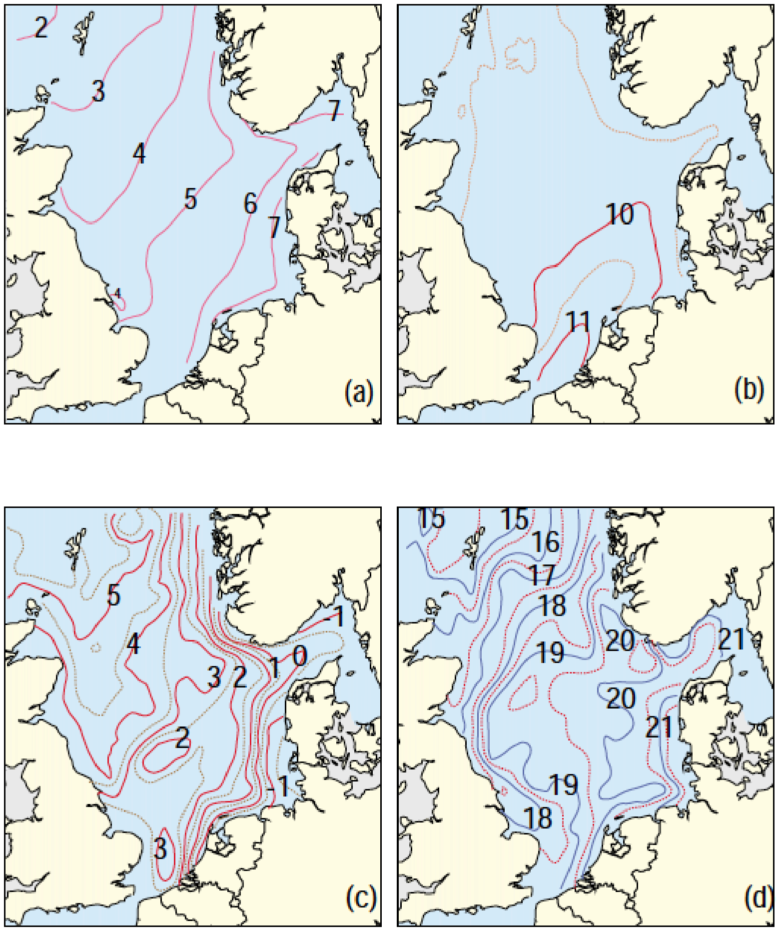


Figure 11 - Sea-surface Temperature Distribution for the North Sea (1969 to 1993): (a) amplitude of yearly cycle, (b) mean, (c) minima, (d) maxima

Source: (OSPAR, 2000) modified from (Becker and Schulz, 2000)

1.1.3 Waves

Figure 12 shows the 50-year extreme surge height and the wave-height distribution and period, based on models and observations. The 50-year maximum wave height at the northern extreme of the North Sea is about 32 metres and decreases steadily to 14 metres as one proceeds toward the coasts of Denmark and The Netherlands.

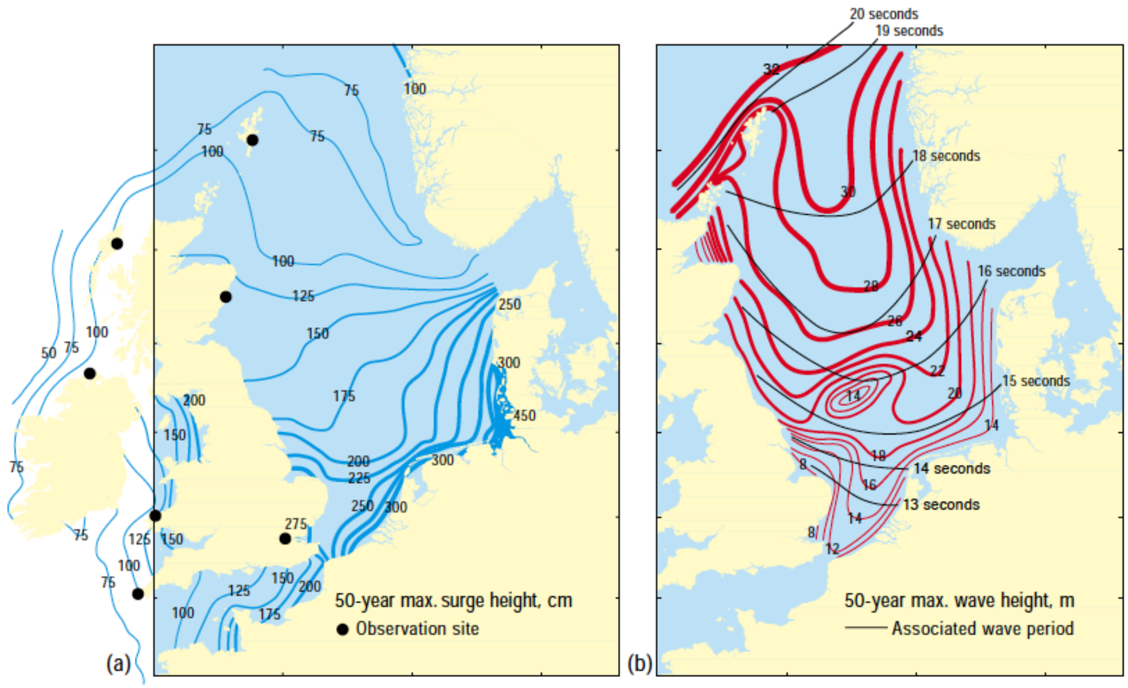


Figure 12 - Estimated 50-year Extreme Surge Height (left) and Wave-height Distribution and Wave Period (right)

Source: (OSAPR, 2000) modified from (Flather, 1987 – left, UK Dept of Energy, 1989 – right)

According to a global hindcast study for 1958 to 1997 (Cox and Swail, 2001), the mean annual significant wave height for the North Sea and coastal Norwegian Sea was 2 to 3 metres, whereas the 99th percentile annual significant wave height was 5 to 7 metres for the North Sea and 7 to 9 metres for the coastal Norwegian Sea. It is difficult to determine by observation how consistent these values are with those in Figure 12.

1.3.4 Sea Ice and Icebergs

Strong currents carrying temperate waters keep the North Sea and Norwegian Sea free of sea ice and icebergs throughout the year. Whereas the Baltic Sea typically is covered to a large extent with sea ice, it has not ventured past the Danish Straits in modern times.

1.4 Geology

This section discusses the North and Norwegian Seas' geological features such as coastal environment (including tides), surficial sediments and lithostratigraphy, and seismicity.

1.4.1 Coastal Environments

The Norwegian coast consists of mountains meeting the sea, fjords and archipelagoes to the north and flatter less extreme terrain to the south. The Scottish coast is similar to the Norwegian, but less severe, having lower cliffs and softer ground. The east coast of England is home to many estuaries and low-lying marshlands, whereas along the English Channel in the southeast, low cliffs and flooded river valleys dominate. The coasts of Belgium and Denmark are predominantly sandy (Encyc Brit Online, OSPAR, 2000).

Spring tidal ranges are from 3 to 6 metres on the English and Scottish coasts and 1 to 3 metres on the remaining North Sea coastlines (OSPAR, 2000).

1.4.2 Surficial Sediments and Lithostratigraphy

The North Sea floor consists of an ancient continental drift depression, lying roughly on a northwest-southeast axis. The depression has been filled with sediment several kilometres thick, originating from the surrounding lands (OSPAR, 2000). This axis is apparent as mud and sandy mud, in Figure 13, which shows the surficial sediments of the North Sea.

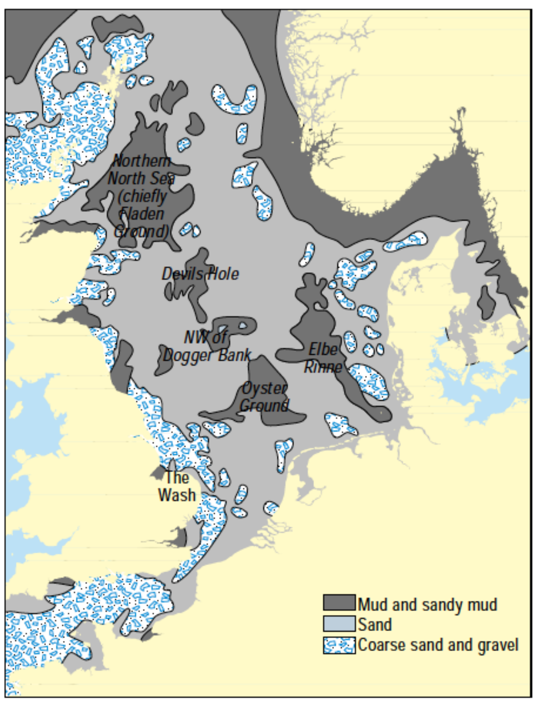


Figure 13 - Surficial Sediments of the North Sea

Source: (OSPAR, 2000) modified from (Eisma, 1981)

Figure 14 shows generalized stratigraphy of the central and northern North Sea. Below the surficial sediments, there is sandstone in much of the upper layer, followed by mudstone and shale farther down.

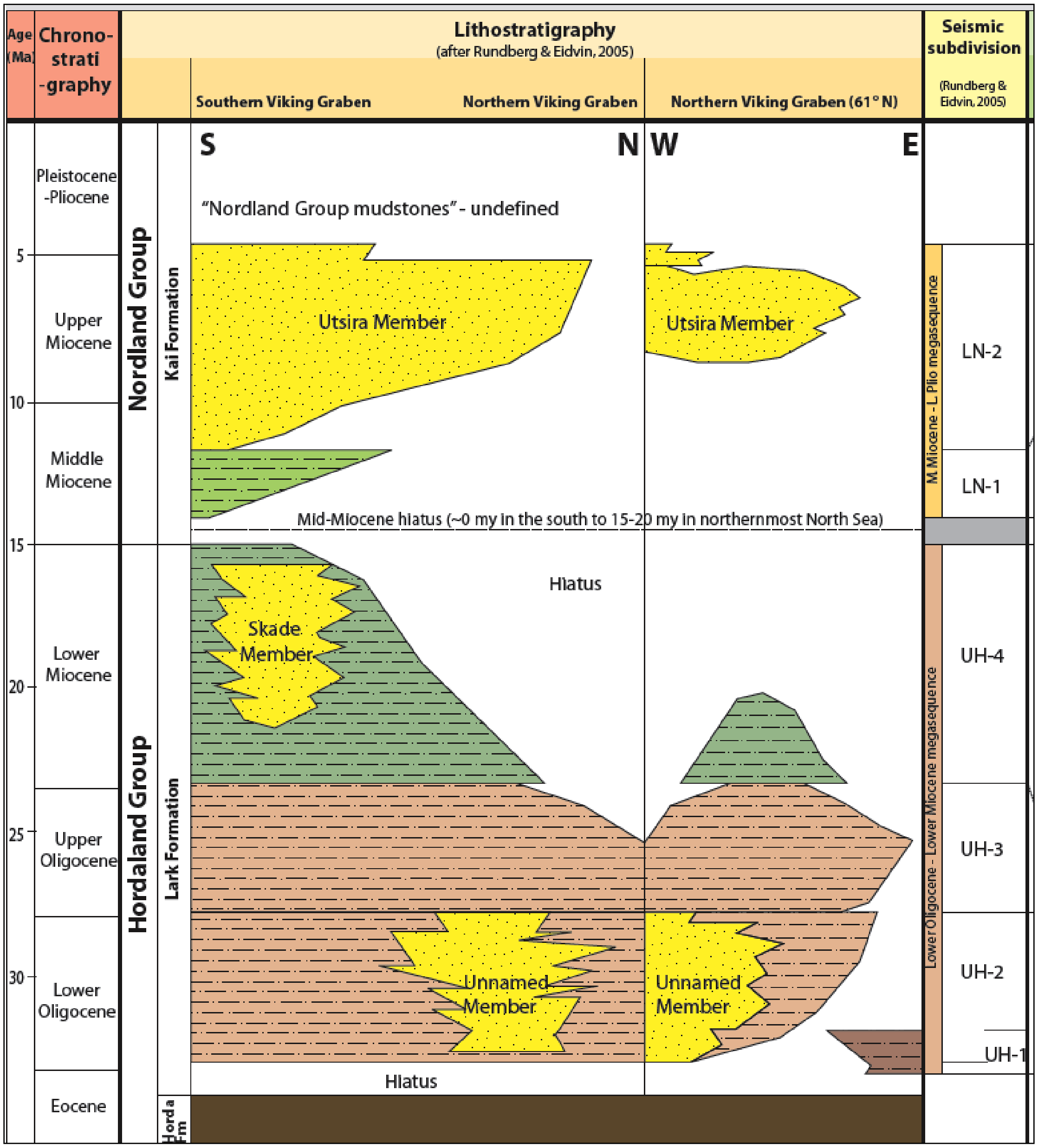


Figure 14 - Generalized Stratigraphy of the Central and Northern North Sea

Source: Modified from (NORLEX)

1.4.3 Seismicity

Seismic activity in Norway and the United Kingdom is considered moderate, with few earthquakes noted by humans each year. There are only a limited number of historical earthquakes that have ever caused damage to buildings and infrastructure (Geological Survey of Norway, British Geological Survey).

Figure 15 shows a map of all earthquakes in Northern Europe from 1965 to 2007. Whereas there is occasionally an earthquake having a magnitude as high as 5, the vast majority of earthquakes are magnitude 4 or less.

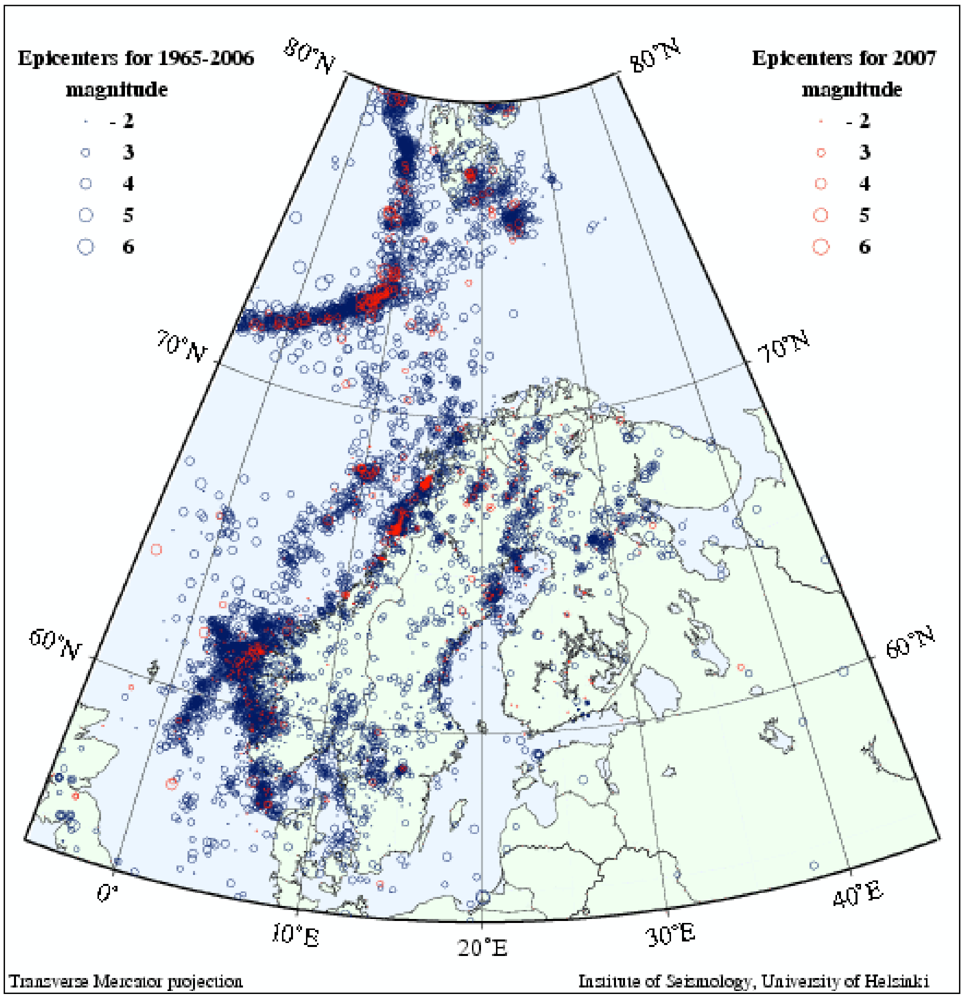


Figure 15 - Earthquakes in Northern Europe from 1965 to 2007

Source: (University of Helsinki – Institute of Seismology)

2.0 Gulf of Mexico (United States of America)

2.1 Introduction

The Gulf of Mexico is a large body of water, covering an area of over 1.55 million km^2, and is bordered by the United States to the north, Mexico to the south and Cuba to the southeast. The basin itself has a wide shallow border surrounding an extensive pit, which reaches down to a maximum depth of 4 384 metres. The waters on the continental shelf (< 200 metres) and the continental slope (200 to 3 000 metres) each represent roughly 20% of the gulf's area (EPA – Gulf of Mexico Program).

The US coastline on the Gulf of Mexico extends roughly 2 700 kilometres. As of 2009, the five American states (from west to east: Texas, Louisiana, Mississippi, Alabama, Florida) surrounding the Gulf of Mexico had a population of 55.47 million (US Census Bureau).

The major offshore oil and gas production region for the American portion of the Gulf of Mexico extends along the continental shelf (and down its slope) from the US-Mexican Border to just east of the Mississippi River delta. Over half the active leases are in water depths greater than 1 000 metres, although only a fraction of the approved drilling applications and less than 1% of active platforms are at these depths (MMS – GoM Fast Facts). Wells as deep as 2 700 metres have been drilled in the Cheyenne field of the Gulf of Mexico. The Deepwater Horizon was drilling at a depth of approximately 1 500 metres at the time of its blowout.

Figure 16 shows the geography and bathymetry (500 metre intervals) of the Gulf of Mexico.

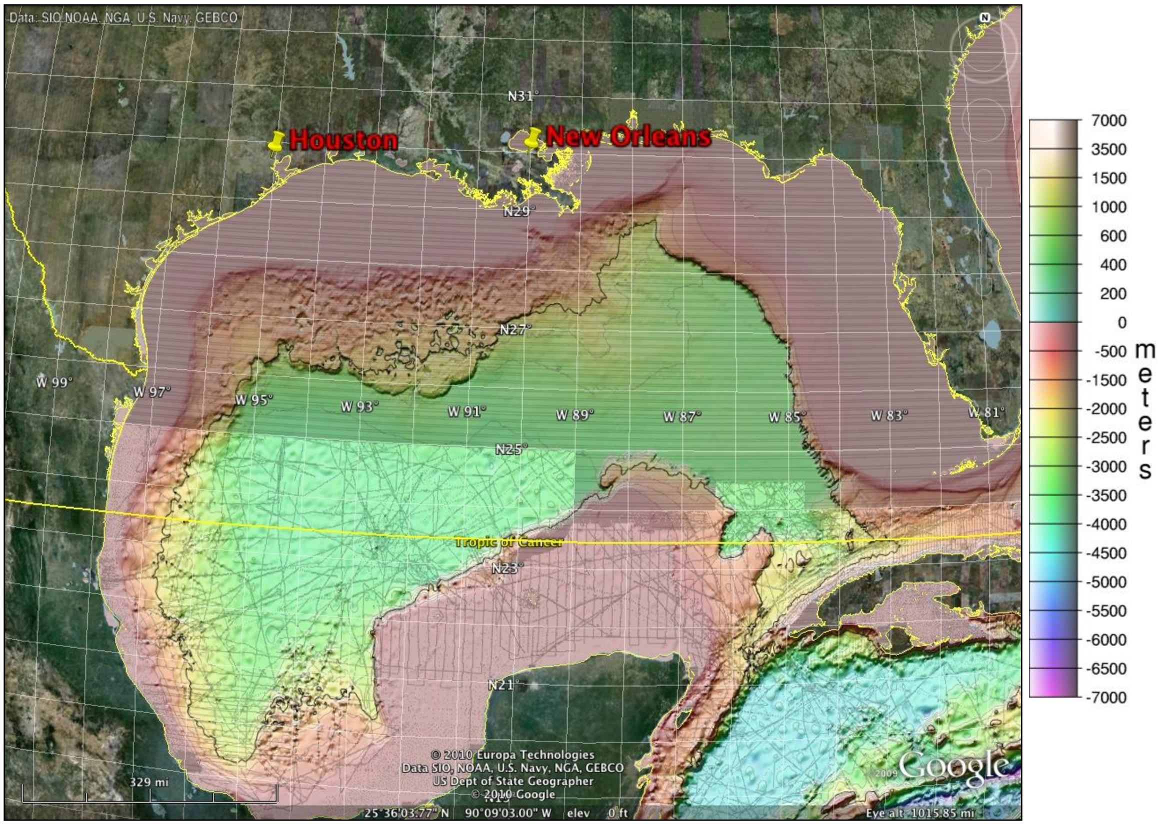


Figure 16 - Geography and Bathymetry (500 metre isobaths) of the Gulf of Mexico

Source: Google Earth using Global Topography V12.1

2.2 Climate

This section discusses the Gulf of Mexico's precipitation, mean and extreme surface air temperatures and wind speeds, as well as tropical storms.

2.2.1 Temperature

Table 7 and Table 8 display climatological conditions for Houston, Texas and New Orleans, Louisiana. Houston lies near the northwestern shoreline of the Gulf of Mexico whereas Louisiana is at the mouth of the Mississippi River. There is relatively little variation in climatology between the two cities: both have record temperature maximums near 40°C and minimums near -15°C, with climatological maximums from 32 to 34°C in the warm season and minimums around 7 or 8°C in the cold season.

Table 7 - Climatological Conditions for Houston, USA (29.76 N, 95.38 W)

Month	Temperature (°C)				Average Precipitation (mm)	Wet Days (>0.25 mm)
	Average		Record			
	Min	Max	Min	Max		
Jan	7	17	-15	29	89	9
Feb	8	18	-14	31	76	8
March	12	22	-5	34	84	8
April	16	26	1	33	91	7
May	19	29	7	37	119	7
June	22	32	13	39	117	8
July	23	33	13	40	99	10
Aug	23	34	12	42	99	10
Sept	21	31	8	38	104	8
Oct	16	27	1	37	94	5
Nov	11	22	-5	32	89	8
Dec	7	17	-9	28	109	10

Source: (BBC World Weather)

Table 8 - Climatological Conditions for New Orleans, USA (29.97 N, 90.05 W)

Month	Temperature (°C)				Average Precipitation (mm)	Wet Days (>0.25 mm)
	Average		Record			
	Min	Max	Min	Max		
Jan	8	17	-9	28	117	10
Feb	10	18	-14	29	107	12
March	13	22	-2	32	119	9
April	16	25	3	32	122	7
May	20	28	11	36	114	8
June	23	31	14	39	140	13
July	24	32	19	39	168	15
Aug	24	32	17	38	147	14
Sept	23	30	12	37	122	10
Oct	18	26	4	34	89	7
Nov	13	21	-2	32	97	7
Dec	9	18	-7	29	117	10

Source: (BBC World Weather)

Figure 17 shows maps of the climatological (1979 to 2009) mean surface air temperature for February and August. The surface air temperature for the northern Gulf of Mexico ranges from 14 to 18°C in February and is spatially consistent around 28°C in August. The values show good agreement with the range of temperatures shown in Table 7 and Table 8 above, and give an idea of the spatial variability of air temperature within the region.

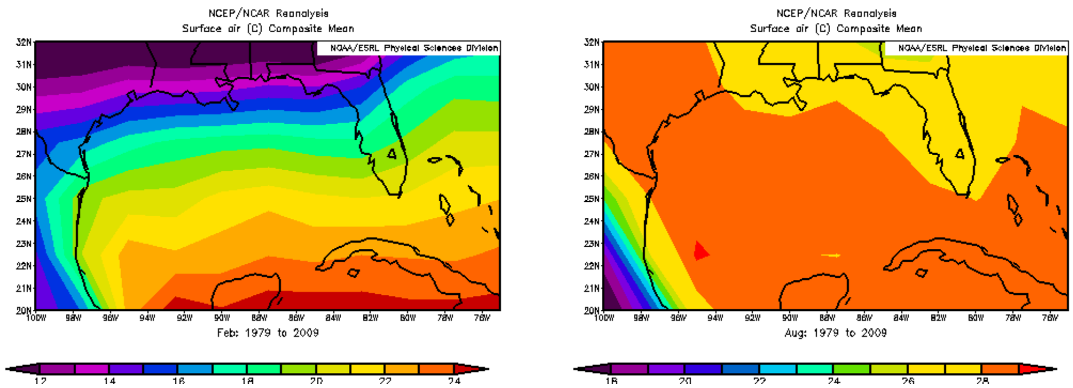


Figure 17 - Climatological Maps for Mean February (left) and August (right) Surface Air Temperatures in the Gulf of Mexico

Source: (NOAA/NCEP Reanalysis Data)

2.2.2 Precipitation

Louisiana experiences more wet days and average precipitation per month with 10.2 and 121.6 mm respectively, whereas Houston experiences 8.2 wet days and 97.5 mm on an average monthly basis. Figure 18 shows the mean daily precipitation rates for February and August in the Gulf of Mexico.

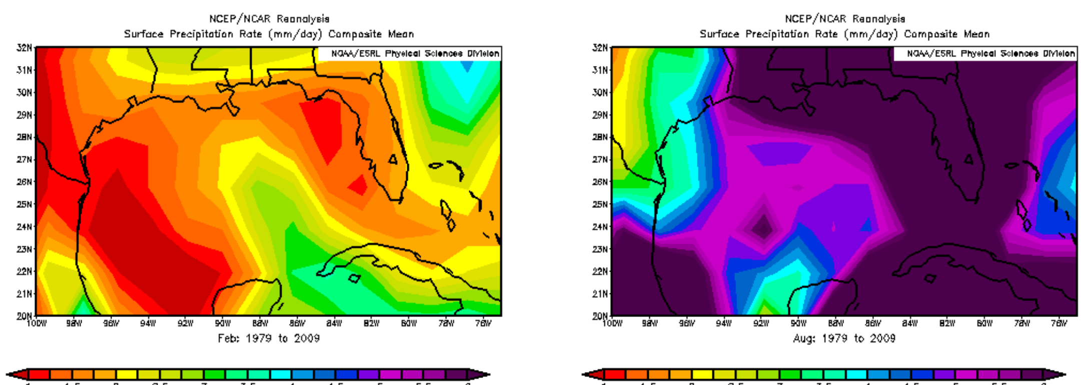


Figure 18 - Climatological Maps for Mean February (left) and August (right) Daily Precipitation Rate in the Gulf of Mexico

Source: (NOAA/NCEP Reanalysis Data)

2.2.3 Visibility

Figure 19 shows the mean annual number of days with fog on the shores surrounding the Gulf of Mexico. The region near the border of Louisiana and Texas experiences the most foggy days per year, with greater than 40. On average, the winter months experience a higher percentage of foggy days than summer (Hardwick 1973).

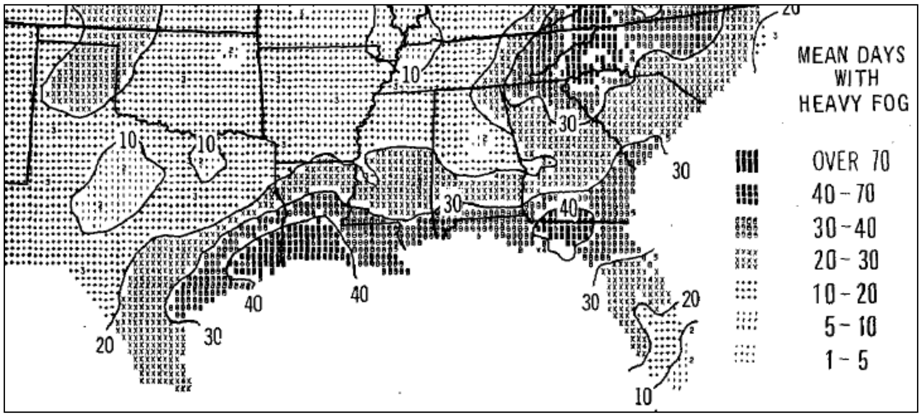


Figure 19 - Fog Climatology for the Gulf of Mexico Region

Source: Modified from (Hardwick, 1973)

2.2.4 Wind

Mean wind speeds over the continental shelf are typically below 6.5 m/s in February and drop to below 4 m/s in August in most regions of interest, as seen in Figure 20. Major wind events are usually the result of tropical storms.

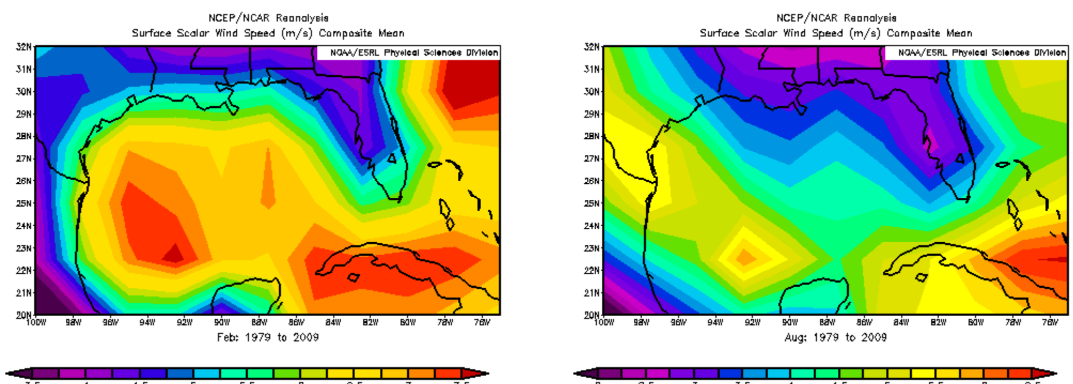


Figure 20 - Climatological Maps for Mean February (left) and August (right) Surface Wind Speeds in the Gulf of Mexico

Source: (NOAA/NCEP Reanalysis Data)

According to a global hindcast study for 1958 to 1997 (Cox and Swail, 2001), the mean annual 6-hour wind speed for the Gulf of Mexico was 6 to 7 m/s, whereas the 99^{th} percentile annual 6-hour wind speed was 13 to 15 m/s, with values decreasing toward the coast. It should be noted that tropical storms and their associated wind speeds were not well resolved in this study.

Table 9, showing the return periods for extreme wave heights, does include data from tropical storms. The 1- and 5-year data is based on winter storm conditions, whereas the 10-, 50- and 100-year data is based on hurricane conditions. The values in the table appear to be relatively consistent with the aforementioned 99th percentile annual 6-hour wind speed.

Table 9 - Return Periods of Extreme Winds in the Gulf of Mexico

Wind Speed (m/s)	Return Period (years)				
	1	**5**	**10**	**50**	**100**
10-min Mean	17.6	25.5	28.4	40.9	41.1
3-sec Gust	22.1	32.0	35.6	51.3	57.8

Source: (ISO 19901-1 2005)

2.2.5 Tropical Storms

The Gulf of Mexico is notorious for its numerous and strong tropical storms. The American National Weather Service says that the Atlantic basin (including the Atlantic Ocean, Caribbean Sea and the Gulf of Mexico) hurricane season runs from the beginning of June until the end of November. From Figure 21, which shows a map of the paths and intensities of tropical storms in the Gulf of Mexico, it is obvious that there is no region in the gulf that is unaffected by hurricanes.

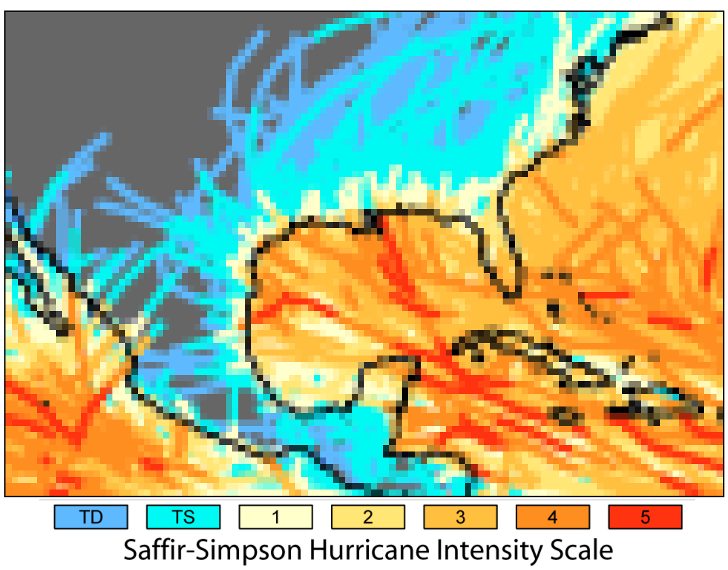


Figure 21 - Paths and Intensities of Tropical Storms in the Gulf of Mexico

Source: Modified from (NASA – Earth Observatory)

Hurricane season peaks from mid-August to late October but intense storms can occur anytime during the season, as shown in Figure 22.

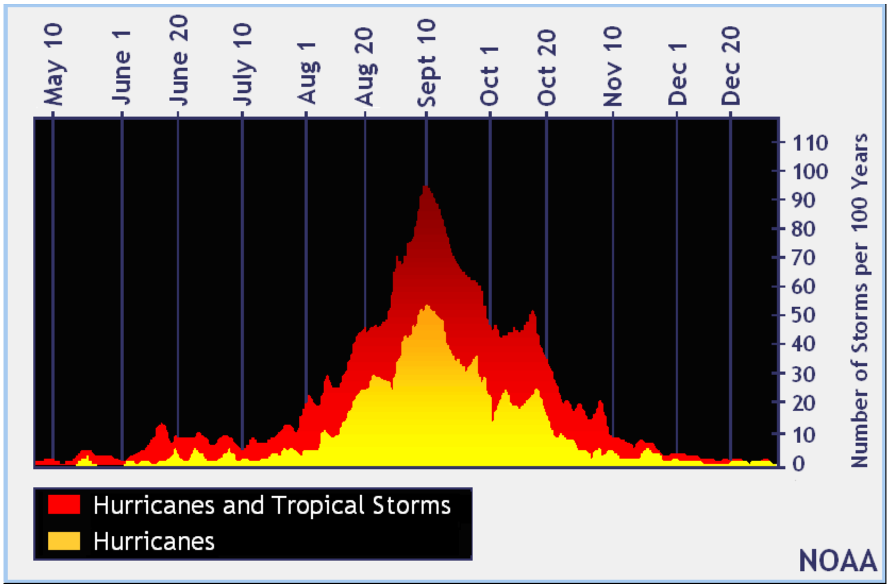


Figure 22 - Number of Tropical Cyclones per 100 years

Source: (NOAA – National Hurricane Center, b)

2.3 Oceanography

This section discusses the major ocean currents, water properties, such as sea-surface temperature and salinity, along with mean and extreme wave heights that affect the Gulf of Mexico.

2.3.1 Currents

The current of primary interest to the American oil-producing regions in the Gulf of Mexico is the Loop Current, shown in Figure 23. The Loop Current connects the Yucatan Current to the south with the Florida Current to the east. It typically flows northwest and can be either a direct connection between the Yucatan and Florida Currents or it can venture far north into the Gulf (as far as 29.1 N near the Mississippi delta) resulting in a clockwise flow (Wiseman and Dinnel, 1988, Vukovitch *et al,* 1979). The current can "pinch off" a warm core ring as it transitions from loop flow to direct flow, which then propagates westward at speeds of 2 to 5 km/day (Coats, 1992, Elliot, 1982).

The Loop Current has a typical transport of 24 to 30 Sv having surface speeds near 80 cm/s (Sheinbaum *et al*, 2002, Coats, 1992).

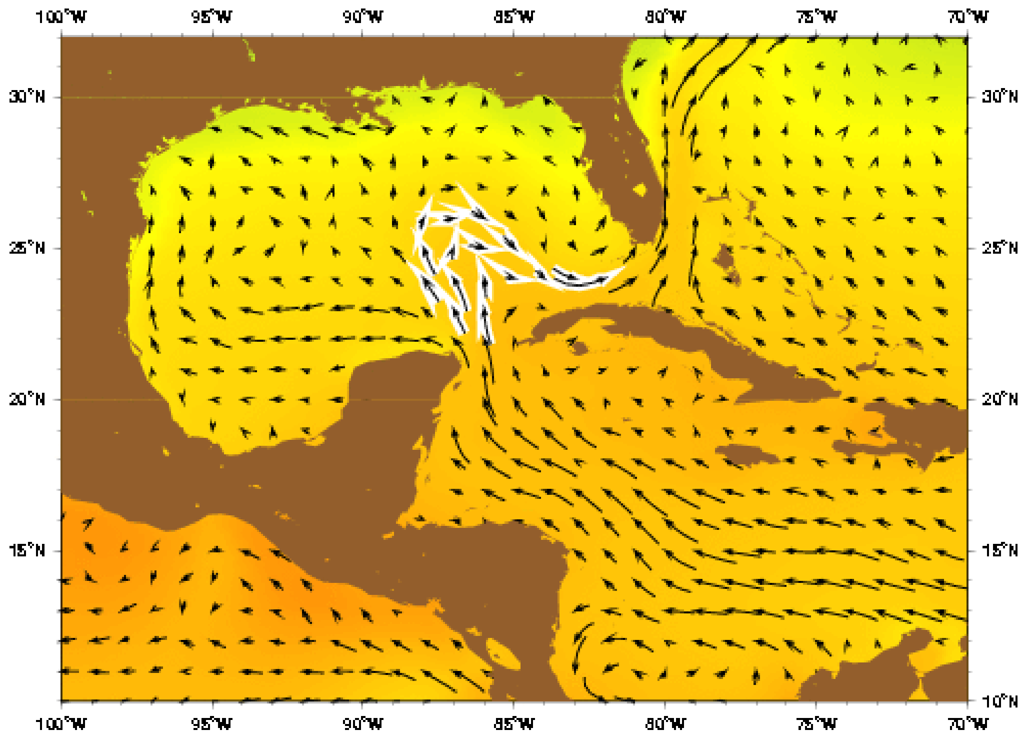


Figure 23 - Map Highlighting the Loop Current

Source: (MGSVA)

2.3.2 Sea-surface Temperatures

Figure 24 shows maps of the climatological (1979 to 2009) mean sea-surface temperature[2] for February and August. The warming effects of the Loop Current and Florida Current in February are apparent, whereas there is a relatively consistent sea-surface temperature throughout the Gulf of Mexico in August. The climatological mean sea-surface temperature for the northern Gulf of Mexico ranges from 17 to 22°C in February and is spatially consistent at around 29°C in August.

[2] Values for sea-surface temperature that appear over land should be ignored, as they are an artifact of the interpolation and smoothing of the analysis procedure.

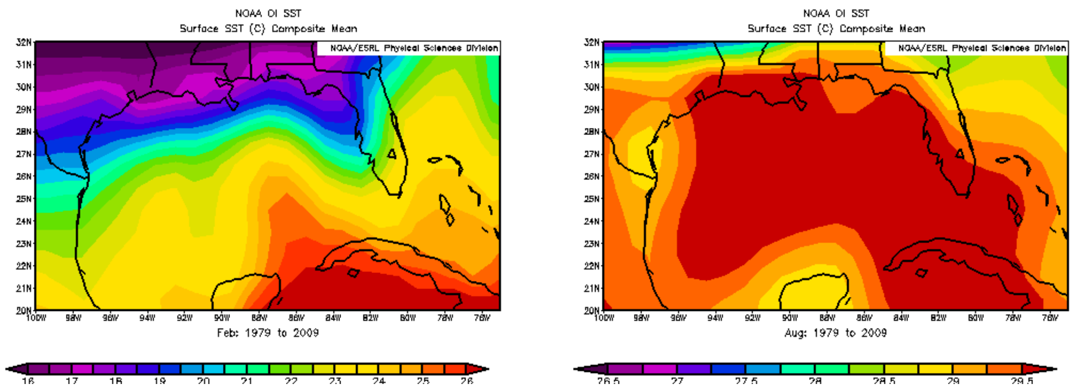


Figure 24 - Climatological Maps for Mean February (left) and August (right) Sea-surface Temperatures in the Gulf of Mexico

Source: (NOAA OI SST)

2.3.3 Waves

According to a global hindcast study for 1958 to 1997 (Cox and Swail, 2001), the mean annual significant wave height for the Gulf of Mexico was 0.5 to 1.5 metres, whereas the 99th percentile annual significant wave height was 3 to 5 metres. It should be noted that tropical storms and their associated wave heights were not well resolved in this study.

Table 10, showing the return periods for extreme wave heights, does include data from tropical storms. The 1- and 5-year data is based on winter storm conditions, whereas the 10- 50- and 100-year data is based on hurricane conditions. It can be seen that the 1-year significant wave height of 4.9 metres shown below corroborates the aforementioned maximum 99th percentile annual significant wave height of 5 metres.

Table 10 - Return Periods for Extreme Wave Heights in the Gulf of Mexico

Parameter	**Return Period (years)**				
	1	**5**	**10**	**50**	**100**
Maximum Wave Height (m)	9.4	13.0	15.0	22.8	25.8
Significant Wave Height (m)	4.9	7.3	8.5	12.9	14.6
Spectral Peak Period (s) (±10%)	10.3	11.7	12.3	14.3	14.9

Source: (ISO 19901-1 2005)

2.3.4 Sea Ice and Icebergs

Neither sea ice nor icebergs ever reach the Gulf of Mexico.

2.4 Geology

This section discusses the northern Gulf of Mexico's geological features such as coastal environment (including tides), surficial sediments and lithostratigraphy, and seismicity

2.4.1 Coastal Environments

The Gulf of Mexico coast can be divided into three regions having distinct physical features. The eastern Gulf coast from southern Florida to Mississippi is primarily low-lying barrier islands, harbouring marshy areas in the Big Bend of Florida. The Mississippi Delta region is dominated by marshy areas and low-lying coastal planes. The western Gulf coast includes long sandy barrier islands in Texas and cheniers (sandy ridges above mud planes) (FEMA 2000).

Spring tides along the northern Gulf of Mexico are usually less than 1 metre, with a normal range less than 50 cm (NOAA Tides and Currents).

2.4.2 Surficial Sediments and Lithostratigraphy

The Gulf of Mexico can be divided into seven distinct geographical provinces (Antoine, 1972): (1) Gulf of Mexico Basin, (2) Northeast Gulf of Mexico, (3) South Florida Continental Shelf and Slope, (4) Campeche Bank, (5) Bay of Campeche, (6) Eastern Mexico Continental Shelf and Slope, (7) Northern Gulf of Mexico. Regions 4 to 6 are not relevant to this review and will not be discussed further.

The Gulf of Mexico Basin, is the deepest part of the Gulf, but also contains the Mississippi Cone, which extends southeast of the Mississippi Trough and is composed of soft sediment. The Northeast Gulf of Mexico extends from east of the Mississippi Delta to the eastern edge of Apalachee Bay (in Florida's Bing Bend region) and is characterized by soft sediments. The South Florida Continental Shelf and Slope runs from Apalachee Bay to the Straits of Florida. It has a generalized progression from soft sediments in the north to carbonate sediments in the south. The Northern Gulf of Mexico stretches from Alabama to the US-Mexico Border and contains thick sediments, mostly from the Mississippi River. There are also widespread salt deposits throughout the region (Murray, 1961) that have helped create local topographic features.

Figure 25 shows the generalized stratigraphy of the northern Gulf of Mexico. The upper layer is characterized by sandy continental sediments to the north and marine silts to the south. Farther down there is organic-rich shale and carbonates.

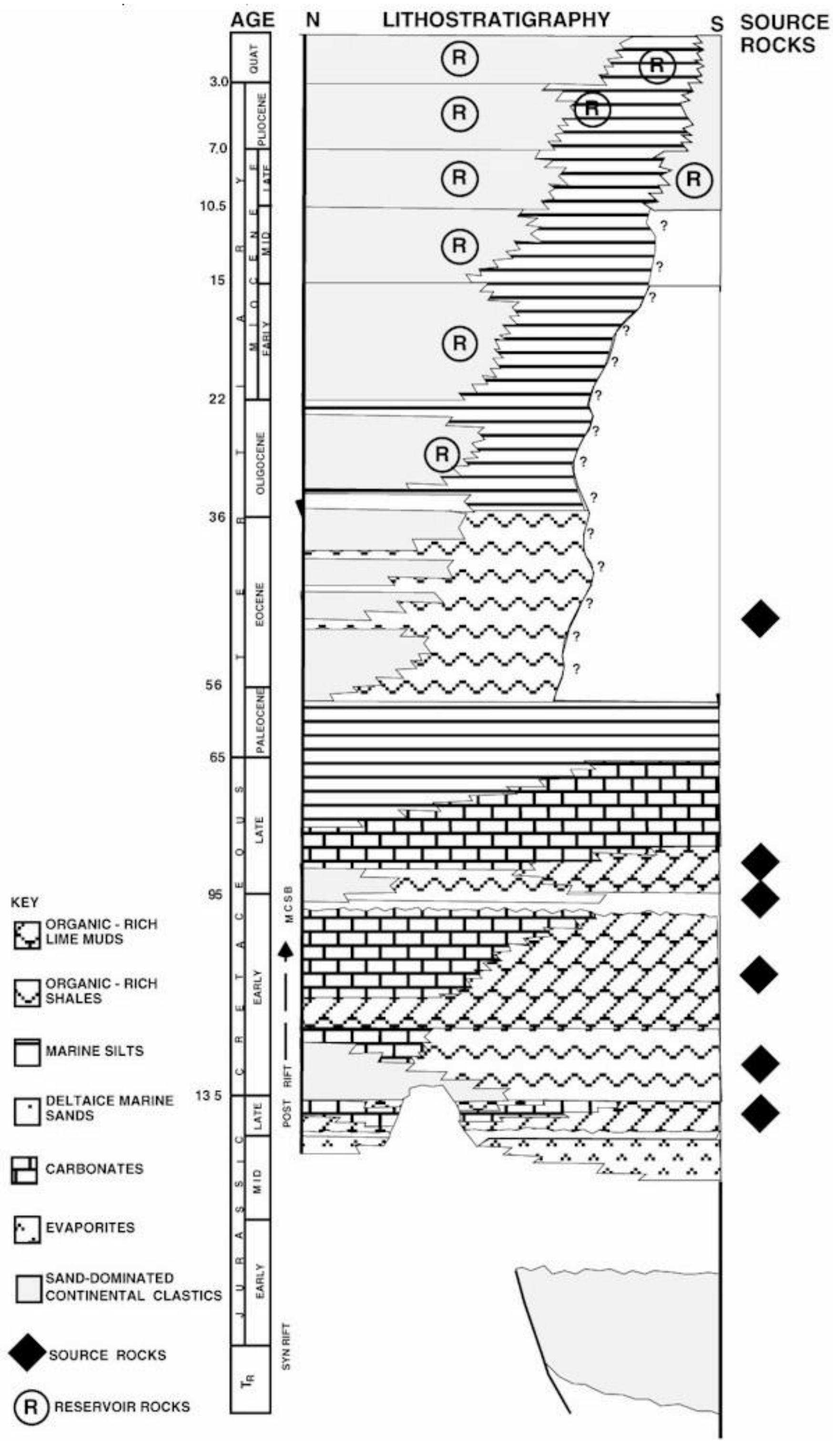


Figure 25 - Generalized Stratigraphy of the Northern Gulf of Mexico

Source: (McBride *et al*, 1998)

2.4.3 Seismicity

As can be seen from Figure 26, there is little significant seismic activity in the Gulf of Mexico, with only a few earthquakes measuring less than 5.5. However, since the map was created in 2002 there was a magnitude 5.8 earthquake on September 11, 2006, with an epicenter 530 kilometres southeast of New Orleans (roughly halfway between the Florida Keys and the southern tip of Louisiana) that was felt in many of the nearby states (USGS – Earthquake Hazards Program).

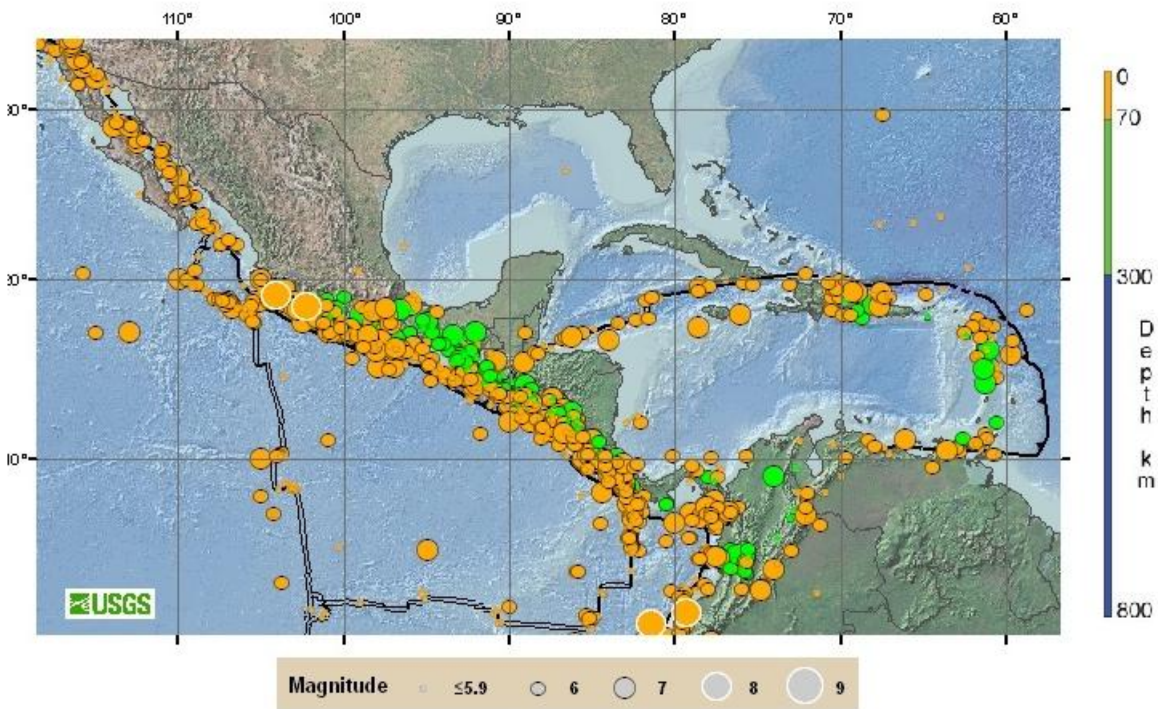


Figure 26 - Seismic Events in the Gulf of Mexico Region Measuring a Magnitude of M5.5 or Greater from 1900-2002

Source: (USGS – Earthquake Hazards Program)

3.0 Australia

3.1 Introduction

The major region of offshore oil and gas production in Australia is on the continental shelf off the west and northwest coasts, between Darwin and Perth. There is also some production near Melbourne in the Bass Strait, which separates Tasmania from mainland Australia. Whereas most operations take place in relatively shallow waters (less than 200 m), Australia has just recently issued drilling permits for waters as deep as 3 750 metres off the western Australian coast. The recent Montara blowout occurred in 77 metres of water.

Western Australia has nearly 13 000 kilometres of coastline and a population of 2.2 million people, 85% of whom live in the southwest corner in, and around, Perth. Victoria, on the northern shore of the Bass Strait has almost 2 000 kilometres of coastline and a population over 5.1 million, over 75% of whom live in the greater Melbourne area. Tasmania has a coastline nearly 6 500 kilometres long, roughly one third of which borders the Bass Strait, and a population near 500 000.

Figure 27 shows the geography and bathymetry (500 metre intervals), of the western Australian offshore region.

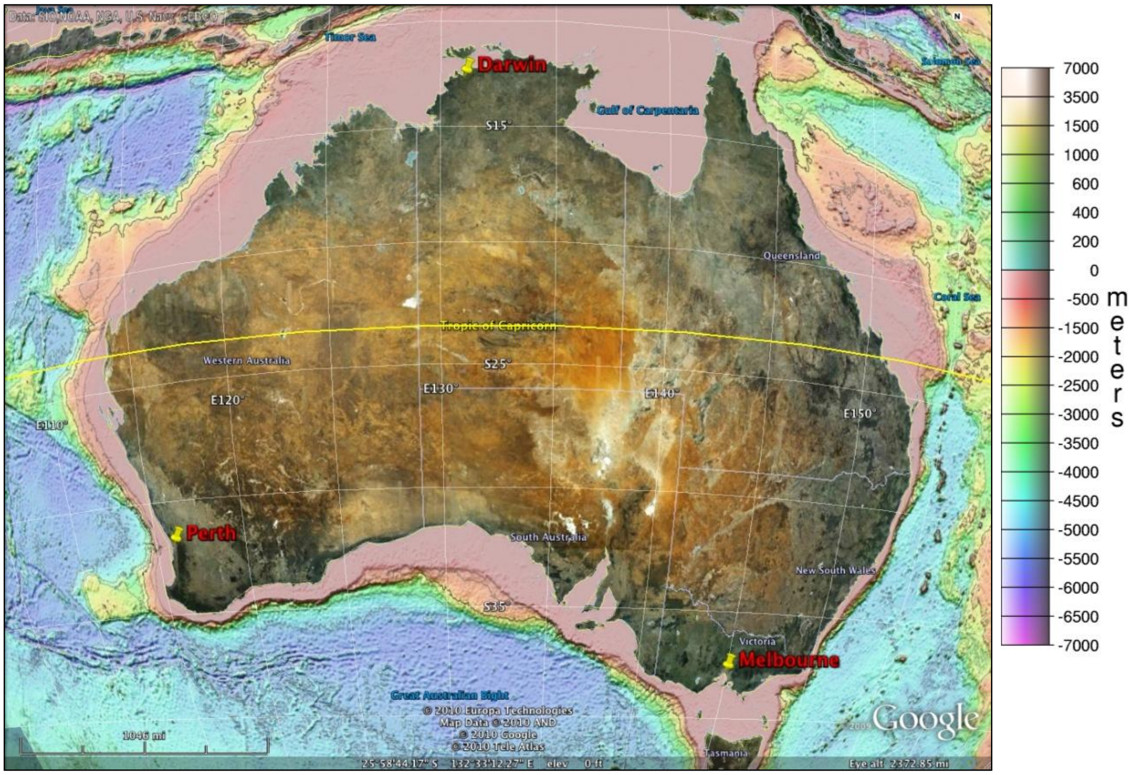


Figure 27 - Geography and Bathymetry (500 metre isobaths) of Australia

Source: Google Earth using Global Topography V12.1

3.2 Climate

Australia ranges from an equatorial and tropical climate in the north, having hot humid summers, to a temperate climate in the south, having warm summers and cool winters. Along the west coast there are also subtropical, desert and grassland climates (Australian Bureau of Meteorology – Climate Classifications).

This section discusses Australia’s precipitation, mean and extreme surface air temperatures and wind speeds, as well as tropical storms.

3.2.1 Temperature

Table 11 to Table 13 display climatological conditions for Perth, on the southwest coast, Darwin, in Australia’s northernmost region and Melbourne, on the shores of the Bass Strait. Whereas the Leeuwin Currents keeps Perth relatively warm, Melbourne is climatologically a few degrees cooler and Darwin is on average 10°C warmer over the run of a year as it lies within the tropics.

The climatological mean temperature in Perth varies from a minimum of 9°C during the Austral winter to a maximum of 29°C in the summer. The record maximum and minimum temperatures are 44°C and 13°C, respectively. Darwin has a consistent climatological maximum throughout the year of 31 to 34°C having a minimum ranging from 19°C in the winter to 26°C in the summer. Similar to Perth, Darwin's record maximum and minimum temperatures are 41°C and 13°C, respectively. Melbourne's climatological maximum and minimum are 26°C and 6°C, respectively.

Table 11 - Climatological Conditions for Perth, Australia (31.95 S, 115.86 E)

Month	Temperature (°C)				Average Precipitation (mm)	Wet Days (>0.25 mm)
	Average		Record			
	Min	Max	Min	Max		
Jan	17	29	9	43	8	3
Feb	17	29	9	44	10	3
March	16	27	8	41	20	5
April	14	24	4	38	43	8
May	12	21	1	32	130	15
June	10	18	2	28	180	17
July	9	17	1	24	170	19
Aug	9	18	2	28	145	19
Sept	10	19	4	33	86	15
Oct	12	21	4	35	56	12
Nov	14	24	6	41	20	7
Dec	16	27	9	42	13	5

Source: (BBC World Weather)

Table 12 - Climatological Conditions for Darwin, Australia (12.45 S, 130.83 E)

Month	Temperature (°C)				Average Precipitation (mm)	Wet Days (>0.25 mm)
	Average		Record			
	Min	Max	Min	Max		
Jan	25	32	20	38	386	20
Feb	25	32	21	38	312	18
March	25	33	20	39	254	17
April	24	33	19	40	97	6
May	23	33	16	39	15	1
June	21	31	13	37	3	1
July	19	31	13	37	0	0
Aug	21	32	14	37	3	0
Sept	23	33	17	39	13	2
Oct	25	34	21	41	51	5
Nov	26	34	21	39	119	10
Dec	26	33	21	39	239	15

Source: (BBC World Weather)

Table 13 - Climatological Conditions for Melbourne, Australia (37.81 S, 144.96 E)

Month	Temperature (°C)				Average Precipitation (mm)	Wet Days (>0.25 mm)
	Average		Record			
	Min	Max	Min	Max		
Jan	14	26	6	46	48	9
Feb	14	26	4	43	46	8
March	13	24	3	42	56	9
April	11	20	2	35	58	13
May	8	17	-1	29	53	14
June	7	14	-2	22	53	16
July	6	13	-3	21	48	17
Aug	6	15	-2	25	48	17
Sept	8	17	-1	32	58	15
Oct	9	19	0	37	66	14
Nov	11	22	3	41	58	13
Dec	12	24	4	44	58	11

Source: (BBC World Weather)

Figure 28 shows maps of the climatological (1979 to 2009) mean surface air temperature for February and August. The heating effects of the Leeuwin Current flowing southward down the west coast can be seen in both the February and August maps. On the western coast, surface air temperatures range from 19°C in the south to 29°C in the north during February and from 12 to 26°C in August. The values show good agreement with the range of temperatures shown in Table 11 to Table 13 above, and give an idea of the spatial variability of air temperature within the region.

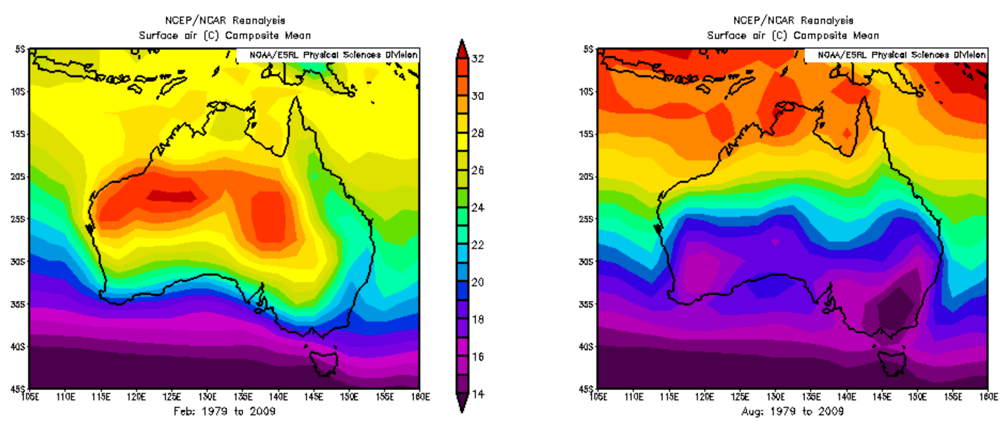


Figure 28 - Climatological Maps for Mean February (left) and August (right) Surface Air Temperatures Offshore Australia

Source: (NOAA/NCEP Reanalysis Data)

3.2.2 Precipitation

Precipitation for Perth and Darwin varies widely throughout the year. Perth has its maximum mean monthly precipitation in June (180 mm) and its minimum in January (8 mm). Darwin has the opposite trend having its maximum in January with the monsoons (386 mm) whereas it typically receives no precipitation as the monsoon cycle reverses in July (0 mm). Melbourne experiences less precipitation, but has more consistent rainfall throughout the year. Figure 29 shows the mean daily precipitation rates for February and August in Australia.

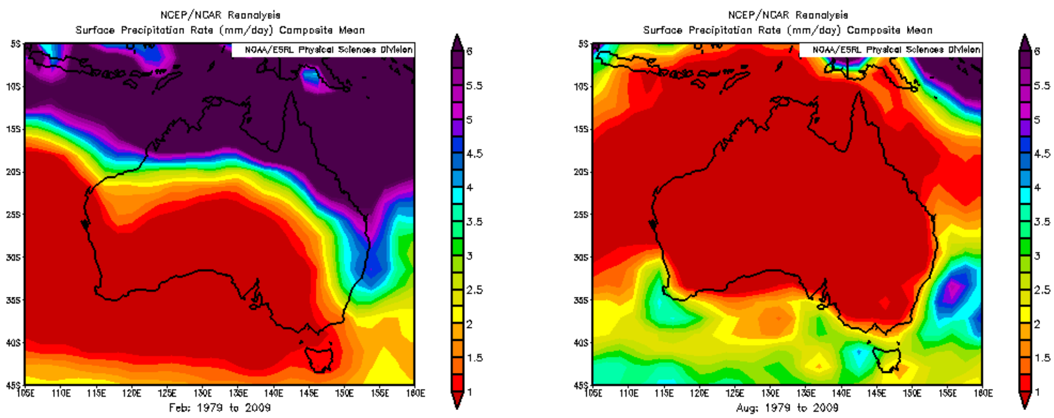


Figure 29 - Climatological Maps for Mean February (left) and August (right) Daily Precipitation Rates Offshore Australia

Source: (NOAA/NCEP Reanalysis Data)

3.2.3 Visibility

Figure 30 maps Australia’s fog climatology based on observations from 1961 to 1990. The Bass Strait region appears to have more foggy days than the west coast.

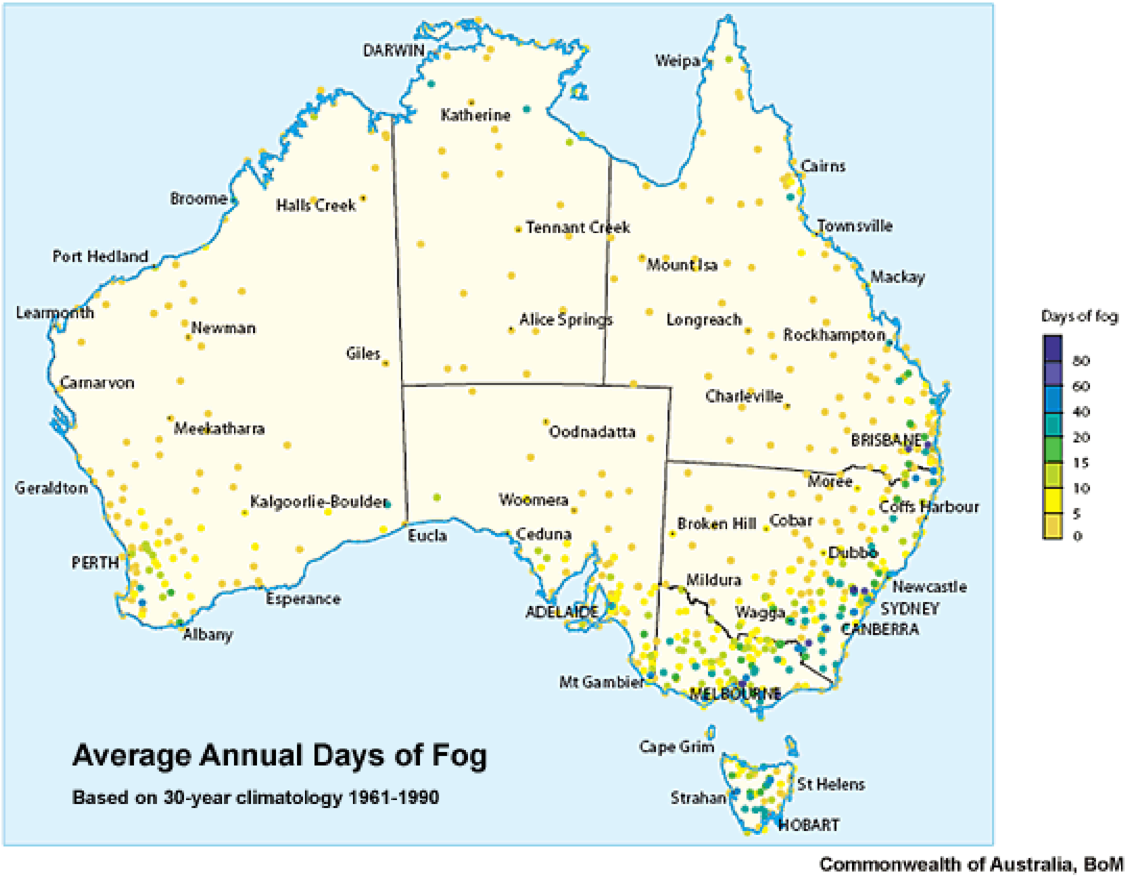


Figure 30 - Fog Climatology of Australia (1961-1990)

Source: (Australian BOM – Fog Forecasting Support Topics)

3.2.4 Wind

The climatological mean surface wind speeds for Australia are presented in Figure 31. In February, mean wind speeds on the west coast reach up to 10 m/s, whereas the northwest coast is relatively calm having mean speeds less than 6 m/s and the Bass Strait has winds blowing around 7 m/s. In August, the mean wind speed ranges from about 4 m/s in the north to 7 m/s on the west coast and about 9 to 10 m/s in the Bass Strait.

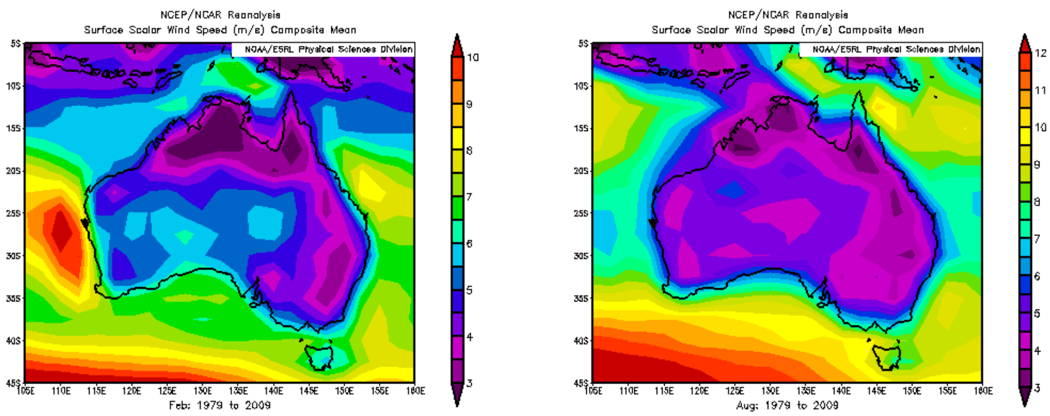


Figure 31 - Climatological Maps for Mean February (left) and August (right) Surface Wind Speeds Offshore Australia

Source: (NOAA/NCEP Reanalysis Data)

According to a global hindcast study for 1958 to 1997 (Cox and Swail, 2001), the mean annual 6-hour wind speeds for offshore northwestern Australia, western Australia and in the Bass Strait were 4 to 6 m/s, 7 to 8 m/s and 7 to 9 m/s, respectively. The 99th percentile annual 6-hour wind speeds were 11 to 13 m/s, 13 to 15 m/s and 15 to 19 m/s, respectively, with values decreasing toward the coast. It should be noted that tropical storms and their associated wind speeds were not well resolved in this study.

Figure 32 shows the 500-year maximum gust wind speeds for onshore Australia, caused by both cyclonic and non-cyclonic events. The maximum gusts (> 80 m/s) are shown to be on the northwest coast, where there is a relatively high concentration of offshore industry activity. It is important to note that offshore wind speeds would likely be higher than those shown in the figure.

Figure 32 - Cyclonic and Non-Cyclonic 500-year Return Period Gust Wind Speeds (m/s)

Source: (Wang and Wang, 2009)

The strongest surface wind gust ever recorded on earth was on Barrow Island (20.67 S, 115.38 E) just off the northwest coast of Australia, located near the heart of offshore oil and gas operations. During Tropical Cyclone Olivia on April 10, 1996, at 64 metres above sea level, a 3-second wind gust of 113.2 m/s (407.5 km/hr) was recorded. During the same event, a 5-minute mean maximum wind of 48.9 m/s (176 km/hr) was recorded (ASU-WMO).

3.2.5 Tropical Storms

Australia lies within the tropics and subtropics and as a result is prone to tropical storms. Figure 33 shows a map record of the paths and intensities for nearly 150 years of tropical storms whereas Figure 34 shows a map of average annual frequency of tropical cyclones in the Australian region. The northwest coast, where much of the offshore industry is operating, is most prone to tropical storms.

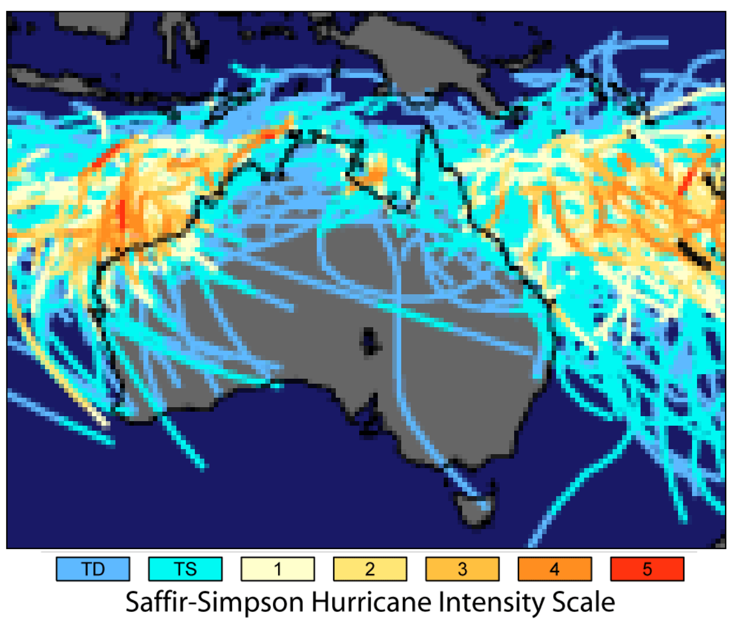


Figure 33 - Paths and Intensities of Tropical Storms Near Australia

Source: Modified from (NASA – Earth Observatory)

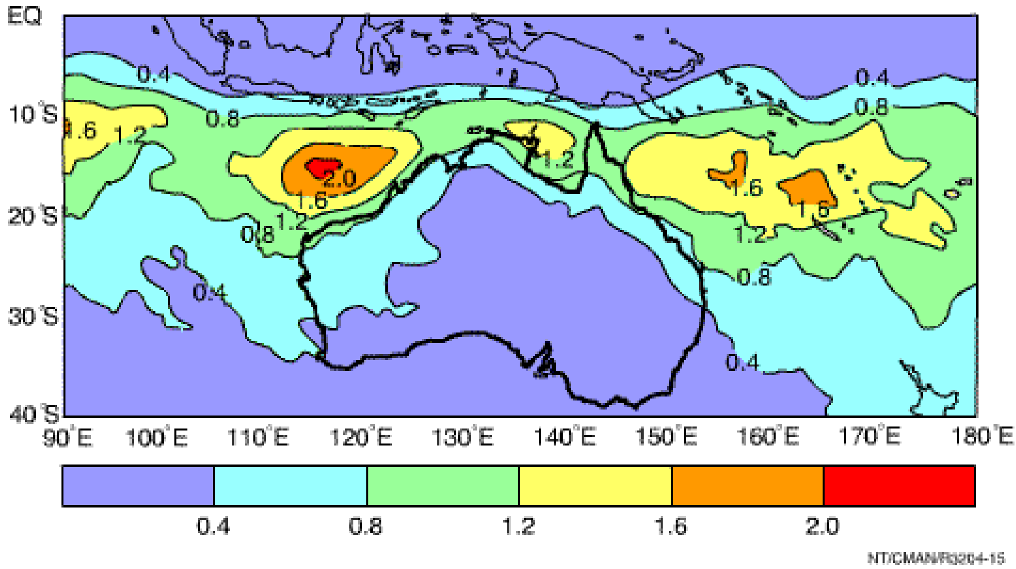


Figure 34 - Map of Average Annual Frequency of Tropical Cyclones in the Australian Region

Source: (Australian Bureau of Meteorology)

3.3 Oceanography

This section discusses the major ocean currents, water properties, such as sea-surface temperature and salinity, along with mean and extreme wave heights that affect Western Australia and the Bass Strait.

3.3.1 Currents

The major currents influencing the coast of western Australia include the South Equatorial Current and the Leeuwin Current.

The South Equatorial Current flows eastward along the northern edge of Western Australia. It is driven primarily by trade winds and is fed by the Indonesian Throughflow via the Timor Sea. It is well developed south of the equator as the monsoonal winds directly above the equator reverse twice a year.

The warm, low-salinity water of the Leeuwin Current flows southward near the coast of western Australia reaching down to 300 metres below the surface. It lies on top of a cold countercurrent called the Leeuwin Undercurrent.

The typical speeds of the Leeuwin Current and its eddies range from 50 to 100 cm/s, having a maximum recorded surface speed of 180 cm/s. It is weakest during the Austral summer months due to strong, opposing southerly winds and is strongest in the fall and winter (Fieux, *et al* 2005, Cresswell, 1991). It also experiences stronger flow during a La Nina phase of the El Nino Southern Oscillation (Feng *et al*, 2003).

A significant amount of flow feeds mesoscale eddies that propagate away from the coast. These eddies are caused by interactions with underwater topography mostly near the Abrolhos Islands and Shark Bay (Batteen *et al*, 2007).

The current in the Bass Strait, which is 240 kilometres wide at its narrowest point and generally around 50 to 70 metres deep, has a velocity around 30 cm/s (Jones, 1980) in a predominantly eastward direction, but is known to be widely varying.

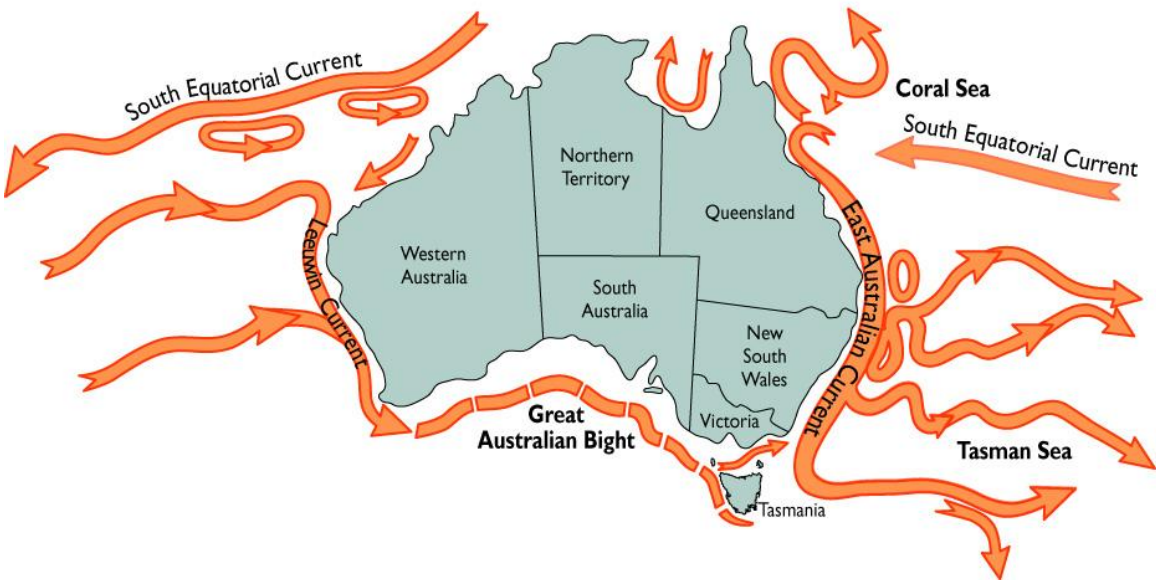


Figure 35 - Schematic of Major Ocean Currents in Australia

Source: (CSIRO – Marine Climate Impacts and Adaptation)

3.3.2 Sea-surface Temperatures

Figure 36 shows the climatic water zones around Australia. It varies from tropical and transition water concentrated in the north to warm and cold temperate waters in the south.

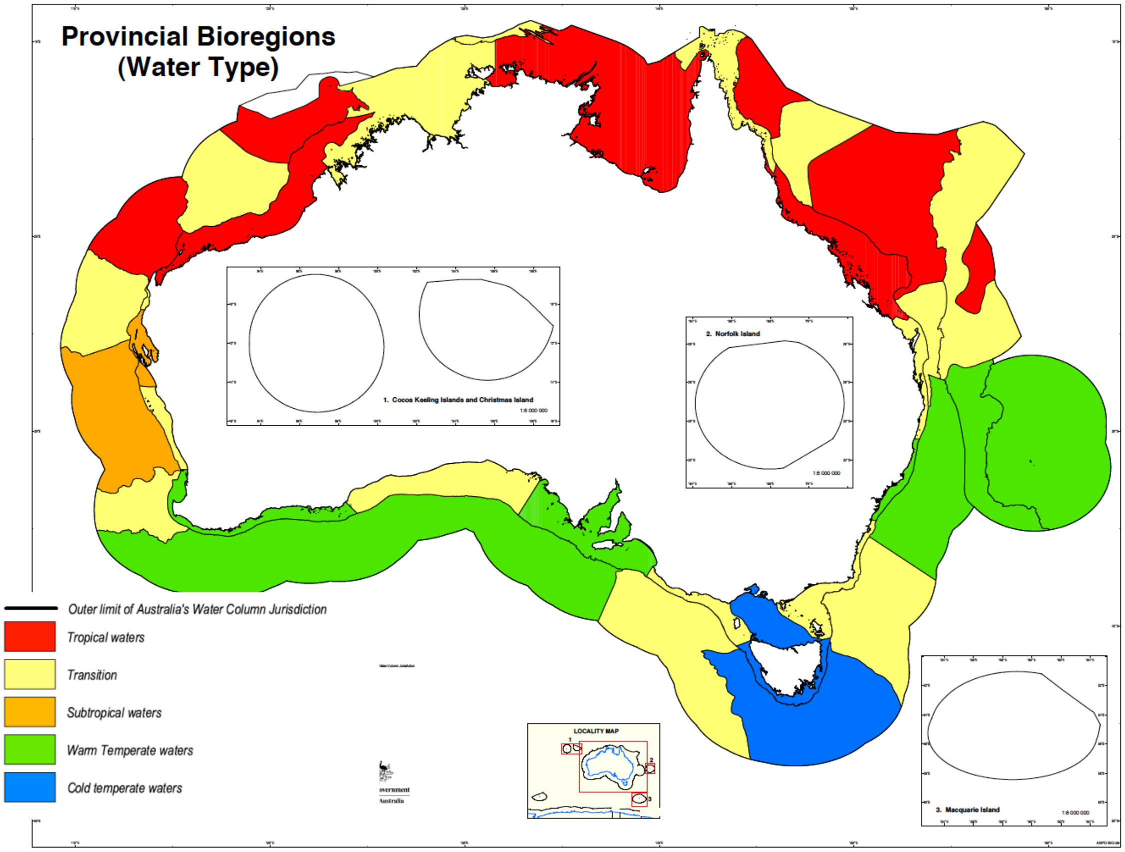


Figure 36 - Climatic Water Zones of Australia

Source: Modified from (Australian Government – Benthic Maps)

Figure 37 shows maps of the climatological (1979 to 2009) mean sea-surface temperature[3] for February and August, respectively. The effects of the Leeuwin Current are more apparent in the Austral winter (August) as that is when its flow is the strongest. Off the northwest coast, the sea-surface temperature ranges from 24 °C in the winter to 30 °C in the summer. The west coast has a stronger temperature gradient, varying from 23 to 17 °C in the winter and 27 to 21 °C in the summer.

[3] Values for sea-surface temperature that appear over land should be ignored, as they are an artifact of the interpolation and smoothing of the analysis procedure.

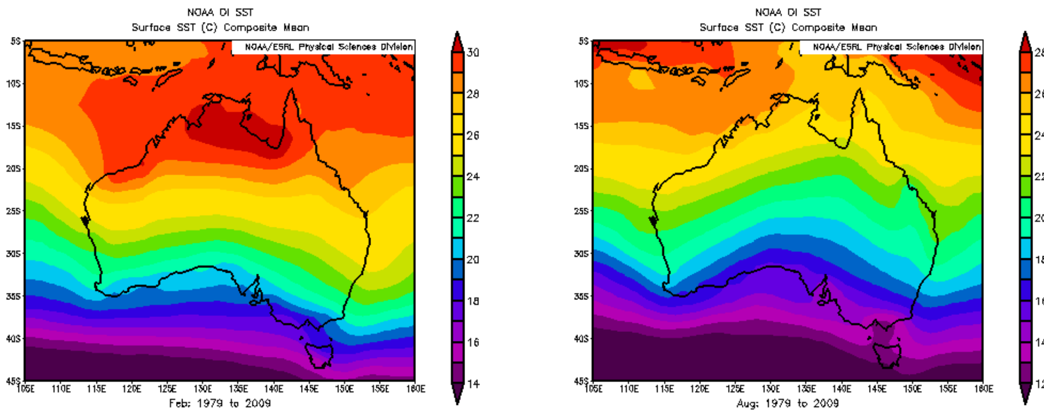


Figure 37 - Climatological Maps for Mean February (left) and August (right) Sea-surface Temperatures Offshore Western Australia

Source: (NOAA OI SST)

3.3.3 Waves

According to a global hindcast study for 1958 to 1997 (Cox and Swail, 2001), the mean annual significant wave heights for offshore northwestern Australia, western Australia and in the Bass Strait were 1 to 2 metres, 2 to 3 metres and 2 to 3 metres, respectively. The 99th percentile annual significant wave heights were 3 to 4 metres, 4 to 5 metres and 5 to 7 metres, respectively. It should be noted that tropical storms and their associated wave heights were not well resolved in this study.

Figure 38 shows the 100-year significant wave heights that are associated with tropical storms of average 30 kilometre radius. The highest significant wave height of about 13 metres occurs off the northwest coast and decreases to about 7 metres in the north and south as one approaches Darwin or Perth, respectively. The 100-year maximum wave height in the Bass Strait is 23 metres (Shinners *et al*, 1988).

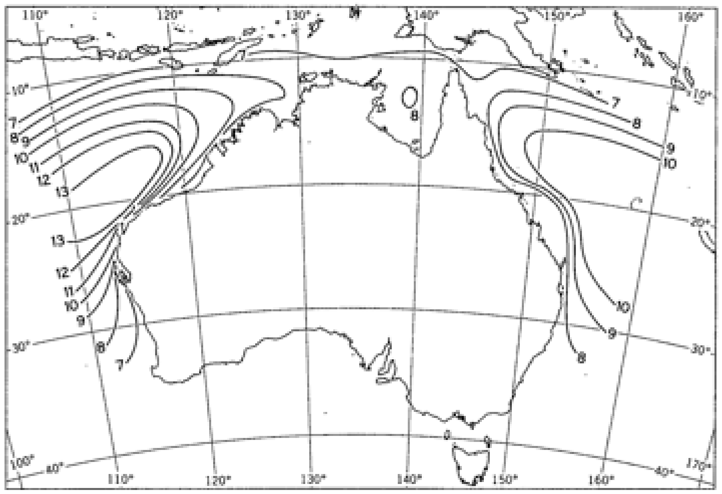


Figure 38 - Extreme Significant Wave Heights (m) for a 100-year return period and average cyclone radius of 30 kilometres

Source: (Dexter and Watson, 1976)

Tsunamis are also a concern for Australia. Figure 39 shows the maximum tsunami amplitude with the return period at 100 metre water depth offshore various regions of Australia. The area at greatest risk is the northwest coast, where there is a relatively high concentration of offshore oil and gas activity. It's important to note that onshore tsunami run-up heights can be several times that of offshore heights (Geoscience Australia, 2008).

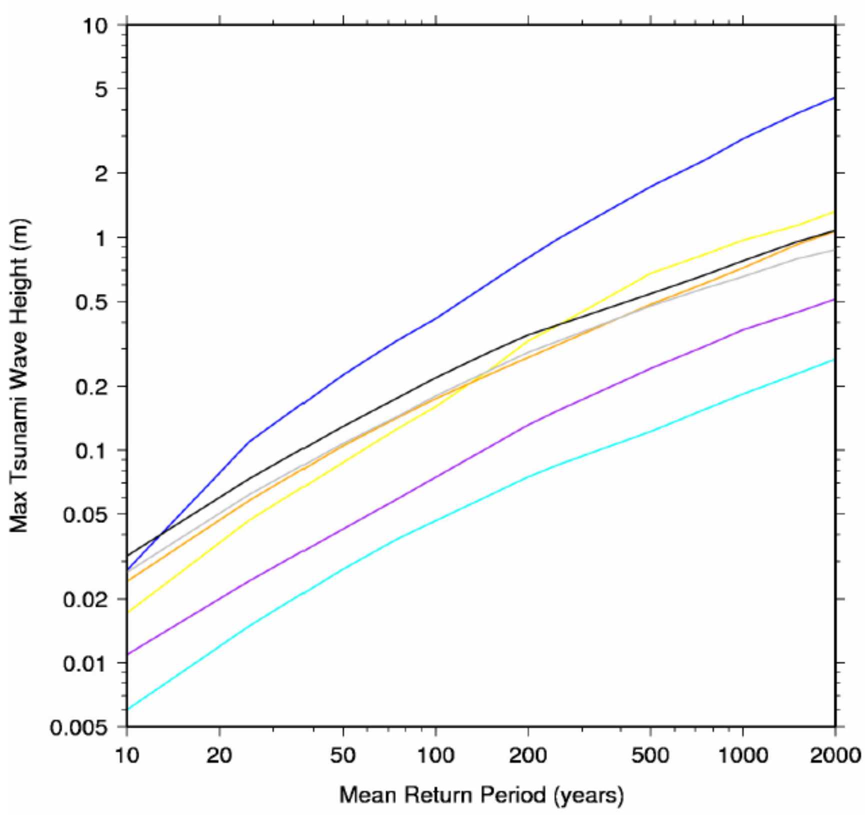


Figure 39 - Maximum tsunami amplitude with the specified return period of being exceeding for various locations at 100-metre water depth offshore Australia

Source: (Geoscience Australia, 2008)

Locations shown in the above figure are central Western Australia (dark blue), southwestern Western Australia (purple), western Northern Territory (yellow), eastern South Australia (cyan), east Tasmania (orange), New South Wales (black), and southeastern Queensland (grey).

3.3.4 Sea Ice and Icebergs

Neither sea ice nor icebergs ever reach the major regions of offshore oil and gas development in Western Australia.

3.4 Geology

This section discusses offshore Australia's geological features such as coastal environment (including tides), surficial sediments and lithostratigraphy, and seismicity

3.4.1 Coastal Environments

The coastal areas surrounding the Bass Strait are primarily sandy beaches and dunes with some cliffs cut in various formations. The west coast also consists mostly of sandy beaches with dunes. On the northwest coast, while there are many sandy beaches, rivers form estuarine gulfs and deltas, and marshy areas that have advanced onto tidal flats often border coastal features. On the coast of Arnhemland, near Darwin, there are extensive cliffs and regions (Schwartz, 2005).

On the west and south coast's, the beaches are primarily wave-dominated whereas on the north and northwest coasts, they are primarily tide-dominated (OzCoasts). Figure 40 shows a map of Australia's tidal ranges, which vary from less than a   on the west cost to 12 metres on the northwest coast and 2 to 3 metres in the Bass Strait.

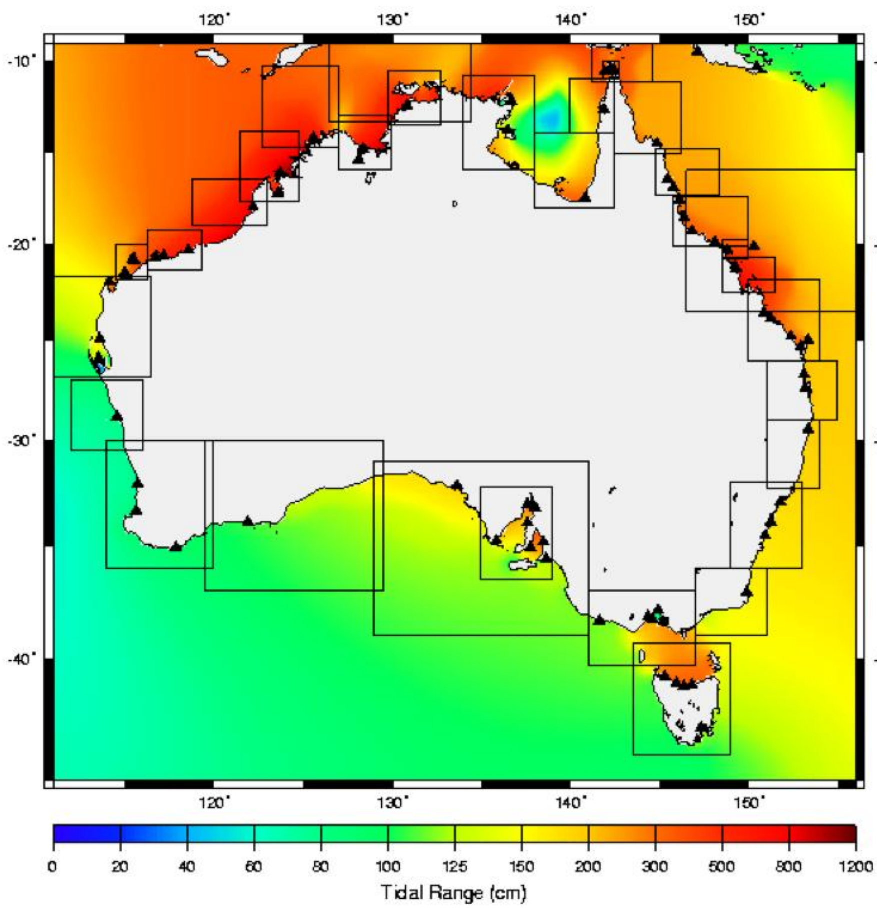


Figure 40 - Tidal Ranges of Australia

Source: (Australian Bureau of Meteorology – Oceanographic Services)

3.4.2 Surficial Sediments and Lithostratigraphy

The maps in Figure 41 highlight the percentage of carbonate, gravel, mud and sand in the seabed surrounding Australia. The shaded regions range in five intervals of 20% from grey (0%) to their respective deepest colours (80-100%). The northwest coast is dominated by carbonate and sand, as is the Bass Strait.

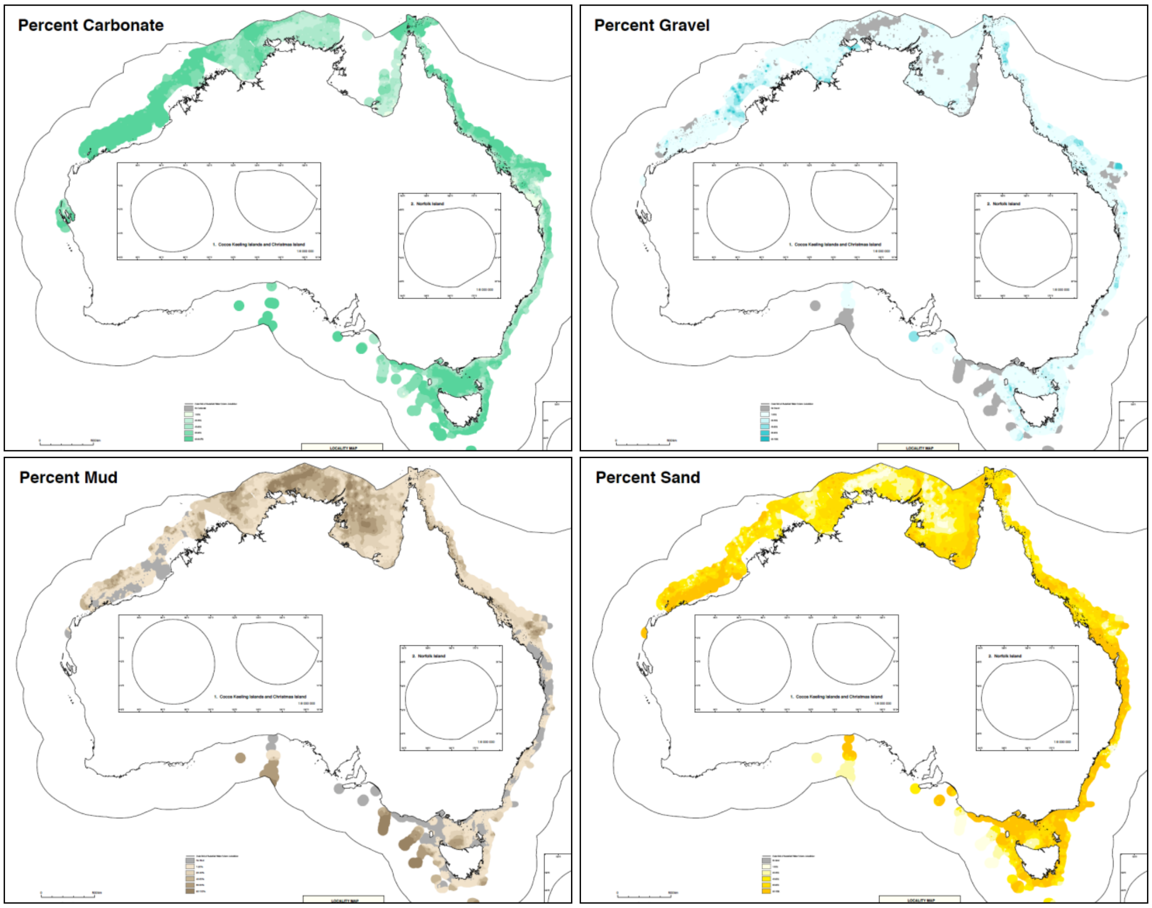
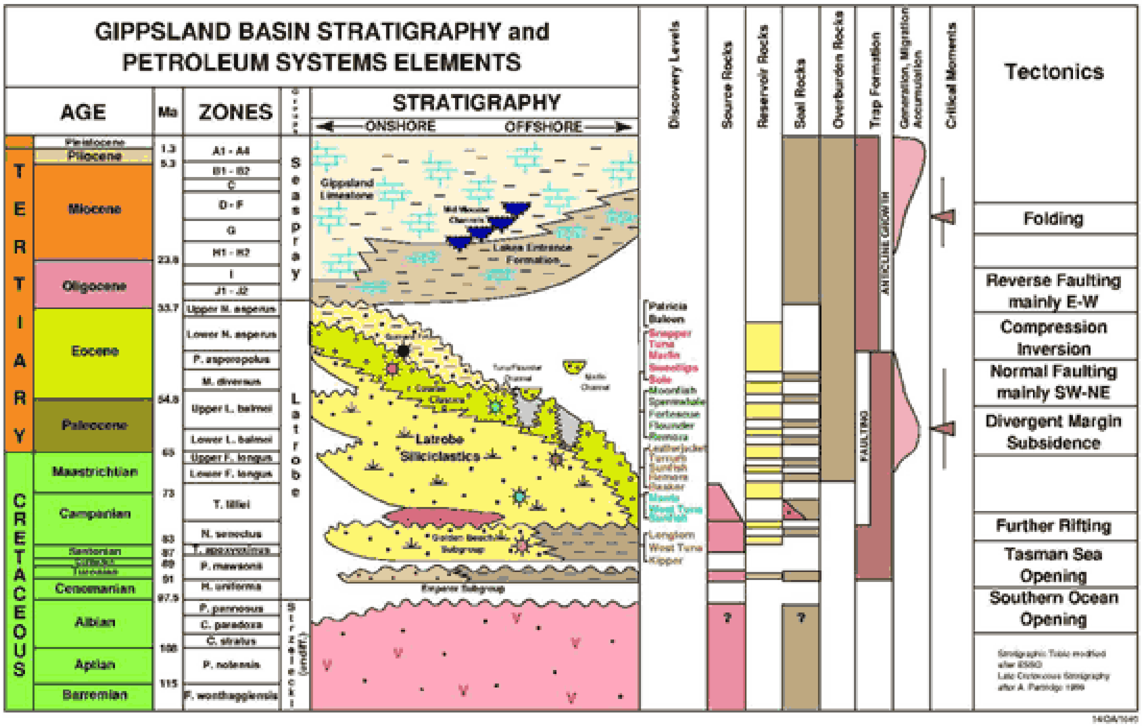


Figure 41 - Spatial Extent of Sediment Composition

Source: (Australian Government – Benthic Maps)

A characteristic stratigraphy of the petroleum region (Gippsland Basin) in the Bass Strait region is shown in Figure 42. This basin is a "failed rift" with sedimentary fill in excess of 10 kilometres (Geoscience Australia - Gippsland Basin). The uppermost layers are dominated by limestone whereas the lower layers range from marine to continental clastics (i.e., sediments).



Generalised stratigraphy showing source, reservoir, seals and plays of the Gippsland Basin.

Figure 42 - Stratigraphy of Gippsland Basin in the Bass Straits Region

Source: (Geoscience Australia - Gippsland Basin)

A characteristic stratigraphy of the Bonaparte Basin, offshore northwestern Australia, is shown in Figure 43. The basin is dominated by limestone near the surface, then claystone and shale, followed by sandstone farther down.

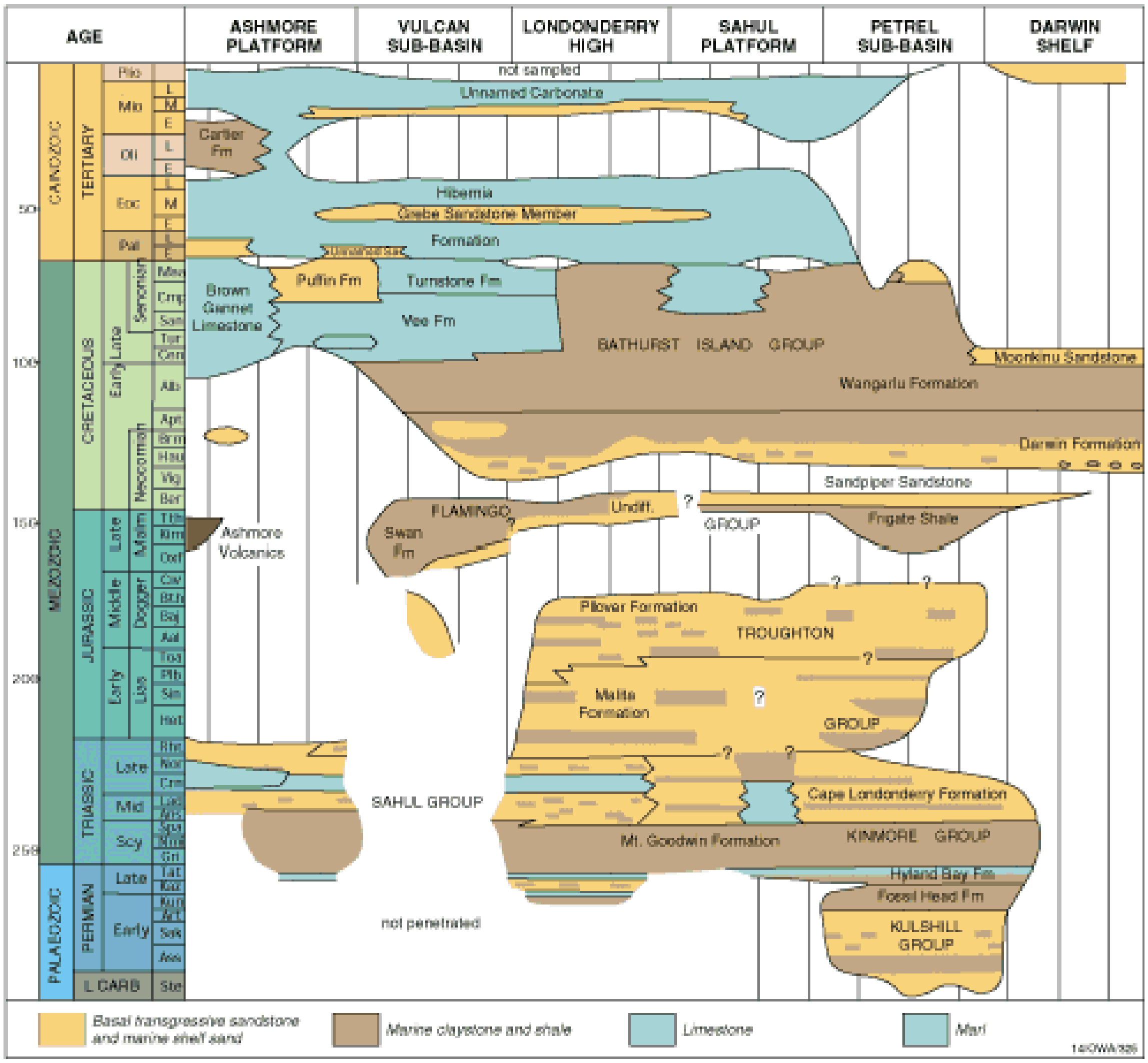


Figure 43 - Stratigraphy of the Bonaparte Basin, Offshore Northwestern Australia

Source: (Geoscience Australia – Bonaparte Basin)

3.4.3 Seismicity

As can be seen from the earthquake map in Figure 44, the regions offshore Western Australia as well as around the Bass Strait are relatively active seismically. Whereas not as active as regions on plate boundaries, such as Japan and California, Australia's earthquake activity is moderate to high compared to other intraplate regions, having earthquakes that can reach above magnitude 7 (University of Queensland – ESSCC).

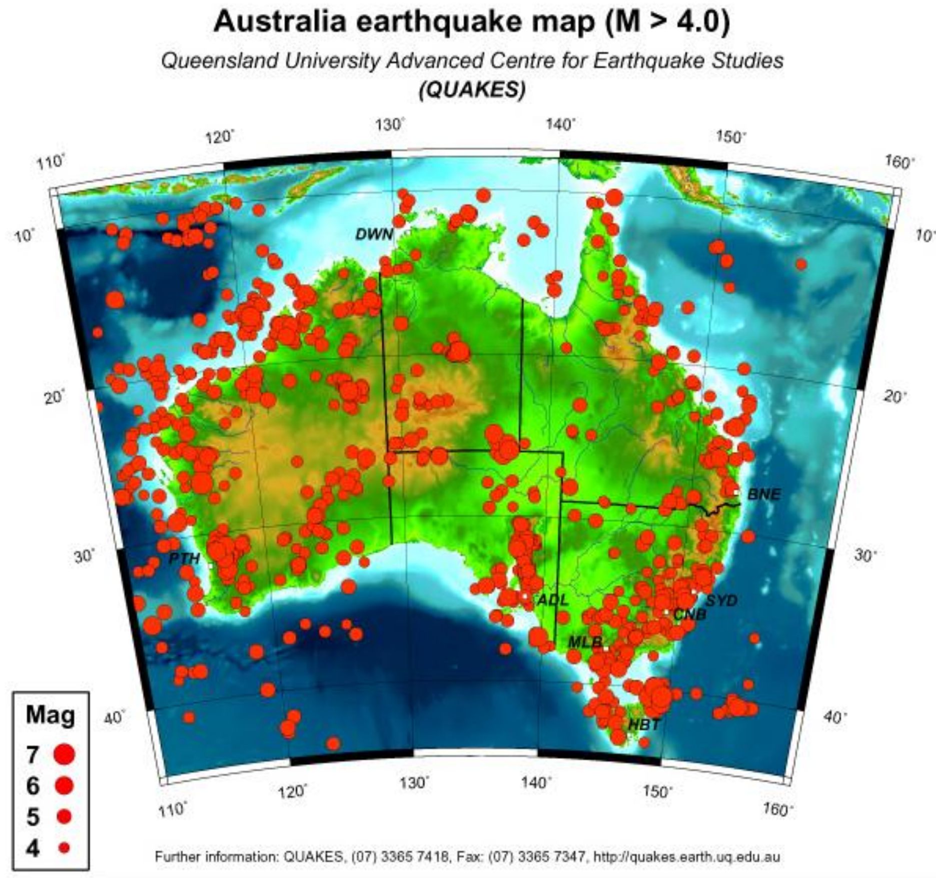


Figure 44 - Australia Earthquake Map

Source: (University of Queensland – ESSCC)

Review of Offshore Oil-spill Prevention and Remediation Requirements and Practices in Newfoundland and Labrador

December 2010

Appendix IV

General Information Concerning Oil-spill Prevention

Appendix IV - General Information on Oil-spill Prevention

1.0 Oil-spill Sources, Causes and Frequency

1.1 Oil-spill Sources

Oil may enter the ocean environment via numerous means. These range from offshore blowouts and tanker-spills to municipal runoffs and natural seeps. Several studies have been published investigating the volumes and contribution from various input sources. Estimates from the National Research Council (NRC) in 1973 and 1981, along with other estimates, are provided in Table 1.

Table 1 - Estimates of Inputs of Petroleum Hydrocarbons Per Year to the World's Oceans

Source	**Year**	1973	1979	1981	1981
	Ref. Source	(NRC, 1975)	(Kornberg, 1981)	(Baker, 1983)	(NRC, 1985)
		Volume (1000's tonnes)			
Urban run-off and discharges		2500	2100	1430 (700-2800)	1080 (500-250)
Operational discharges from tankers		1080	600	710 (440-1450)	700 (400-1500)
Accidents from tankers at sea		300	300	390 (350-430)	400 (300-400)
Losses from non-tanker shipping		750	200	340 (160-640)	320 (200-600)
Atmospheric deposition		600	600	300 (50-500)	300 (50-500)
Natural seeps		600	600	300 (30-2600)	200 (20-2000)
Coastal refineries		200	60	-	100 (60-600)
Other coastal effluents		-	150	50 (30-80)	50 (50-200)
Offshore production losses		80	60	50 (40-70)	50 (40-60)
Total discharges		6110	4670	3570	3200

Source: (GESAMP, 1993) and adapted from (Freedman, 1989)

Note the total discharge from the NRC estimate in 1981 is approximately half of the 1973 estimate. This can be attributed to measures to reduce discharge, but is also largely a factor of enhancements in the estimating procedures. The data are portrayed graphically in Figure 1. The data is converted to percentages to enhance the clarity of individual source contributions.

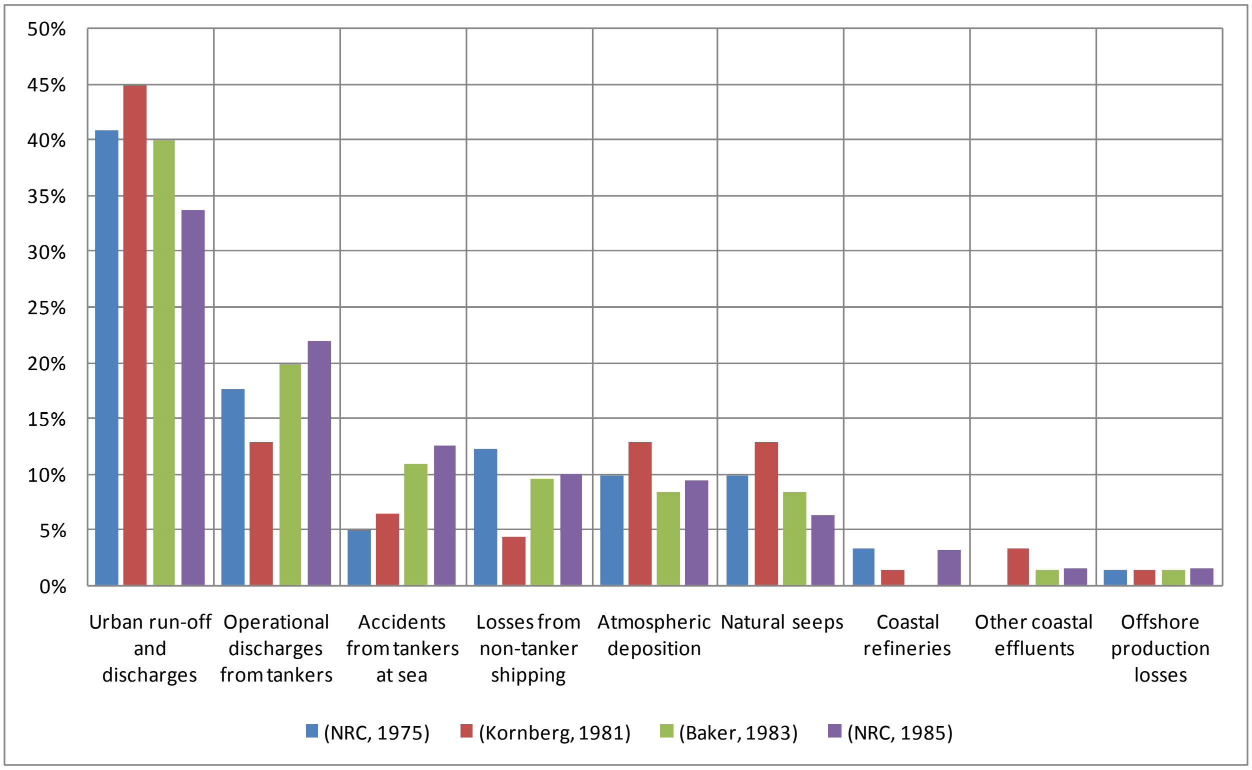


Figure 1 - Estimates of the Inputs of Petroleum to the World's Oceans Prior to 1985

While the numbers vary depending upon the reference source, the general trends are in relative agreement. Urban runoff and discharges have the most significant contribution to hydrocarbon releases into the ocean environment, supplying approximately 40% of the total input. The second largest source is operational discharge from tankers, including the discharge of bilge water from machinery, fuel oil sludge and oily ballast water. This represents nearly 18% of the total hydrocarbon input. The percentage is even larger with the inclusion of non-tanker vessels, adding an additional 9% to the amount. Atmospheric deposition and natural seeps also input significant portions of hydrocarbons, representing approximately 10% and 9%, respectively. Tanker accidents at sea contribute 8% of the total discharge. The inputs from offshore production activities are relatively small in comparison to the previous sources, representing an estimated 2% of the total input.

More recent studies are available providing insight into more up-to-date trends. A study by the NRC in 2002 released estimates of the average input of oil into the sea from 1990 to 1999. This data provides a more detailed breakdown of sources, categorizing them into four major categories; natural seeps, extraction of petroleum, transportation of petroleum and consumption of petroleum. These are further divided into additional subcategories.

Table 2 - Estimate of Annual Release of Petroleum from 1990-1999 by Source

Source	**Volume (1000 tonnes/yr)**							
	North America				**Worldwide**			
	Avg.	**Min**	**Max**	**Percent (%)**	**Avg.**	**Min**	**Max**	**Percent (%)**
Natural seeps	**160**	**80**	**240**	**61.5**	**600**	**200**	**2000**	**46.2**
Extraction of petroleum	**3.0**	**2.3**	**4.3**	**1.2**	**38**	**20**	**62**	**2.9**
Platforms	0.16	0.15	0.18	0.1	0.86	0.29	1.4	0.1
Atmospheric deposition	0.12	0.07	0.45	0.0	1.3	0.38	2.6	0.1
Produced waters	2.7	2.1	3.7	1.0	36	19	58	2.8
Transportation of petroleum	**9.1**	**7.4**	**11**	**3.5**	**150**	**120**	**260**	**11.5**
Pipeline spills	1.9	1.7	2.1	0.7	12	6.1	37	0.9
Tank vessel spills	5.3	4	6.4	2.0	100	93	130	7.7
Operational discharges (cargo washing)	N/A	N/A	N/A	0.0	36	18	72	2.8
Coastal facility spills	1.9	1.7	2.2	0.7	4.9	2.4	15	0.4
Atmospheric deposition	0.01	N/A	0.02	0.0	0.4	0.2	1	0.0
Consumption of petroleum	**84**	**19**	**2000**	**32.3**	**480**	**130**	**6000**	**36.9**
Land based (river and runoff)	54	2.6	1900	20.8	140	6.8	5000	10.8
Recreational marine vessel	5.6	2.2	9	2.2	N/A	N/A	N/A	0.0
Spills (non-tanker vessels)	1.2	1.1	1.4	0.5	7.1	6.5	8.8	0.5
Operational discharges (vessels 100 GT)	0.10	0.03	0.3	0.0	270	90	810	20.8
Operational discharges (vessels < 100 GT)	0.12	0.03	0.3	0.0	N/A	N/A	N/A	0.0
Atmospheric deposition	21	9.1	81	8.1	52	23	23	4.0
Jettisoned aircraft fuel	1.5	1	4.4	0.6	7.5	5	5	0.6
Total	**260**			**100**	**1300**			**100**

Source: Modified from (S.L. Ross Environmental Research Ltd., 2006),(Hawboldt, 2010), with original data from (NRC, 2002)

The data provide average estimates of petroleum input into the sea, as well as minimum and maximum values to capture the uncertainty in the analysis. The percentage columns are based upon the average values. Figure 2 presents a graphical view of the percent input data for both North America and worldwide.

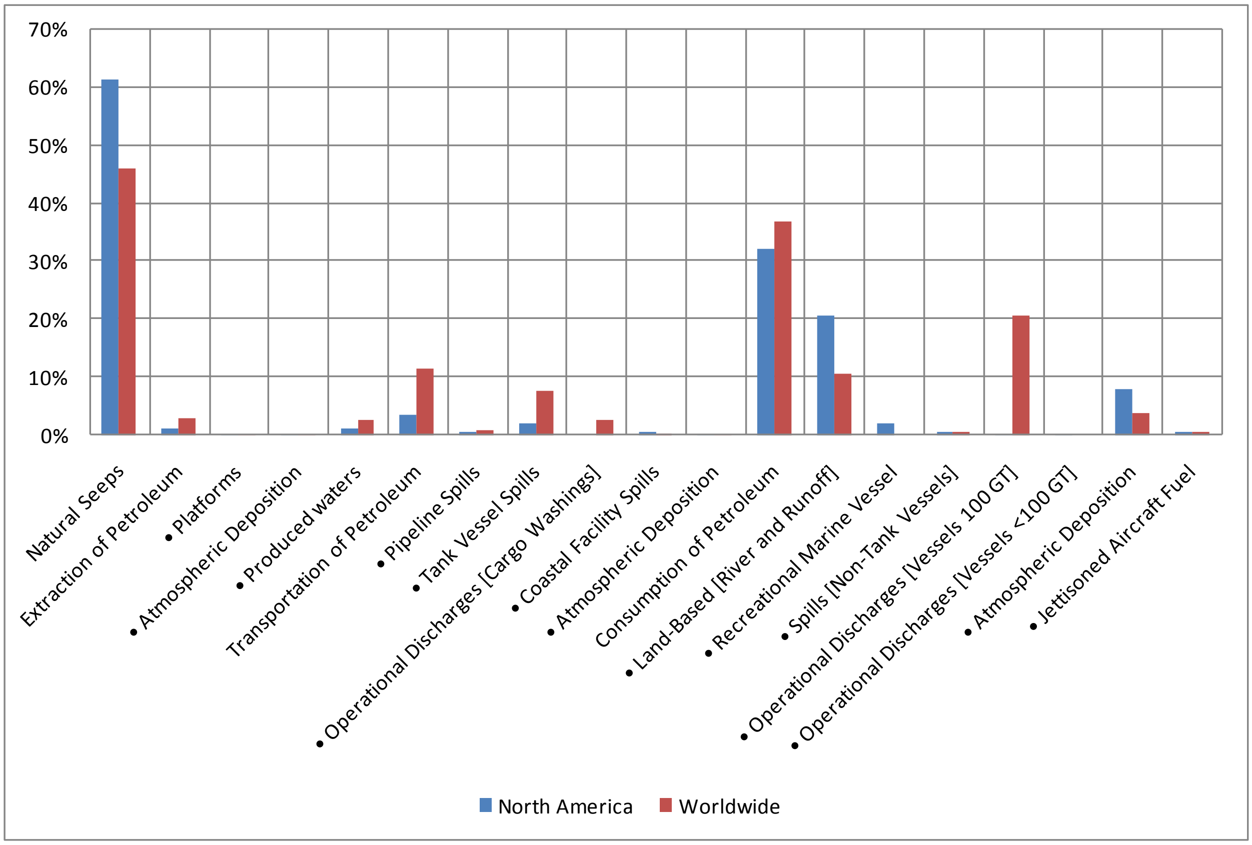


Figure 2 - Estimate of Annual Release of Petroleum from 1990-1999 by Source (percentage)

According to the NRC 2002 study, in North America, natural seeps account for more than 60% of the total input of petroleum into the ocean. Worldwide this number reduces to 46%, but still represents the largest contributing source. Note this contribution is significantly larger than the previous studies in which the input from natural sources contributed only 9% of the total input worldwide. Urban runoff and discharges were the largest source in the previous studies at approximately 40%, but only represent 11% in the recent analysis. The reason for this discrepancy may be due to actual physical changes in the two input sources or it may be related in part to the methods used to estimate their input.

Despite the discrepancies, the studies agree on the input as a result of petroleum production/extraction. Approximately 2-3% of the total oil in the ocean results from offshore production activities.

A more general breakdown of the sources of oil in the ocean is provided in the 1993 report by the Joint Group of Experts on the Scientific Aspects of Marine Pollution (GESAMP). These data are presented in Figure 3.

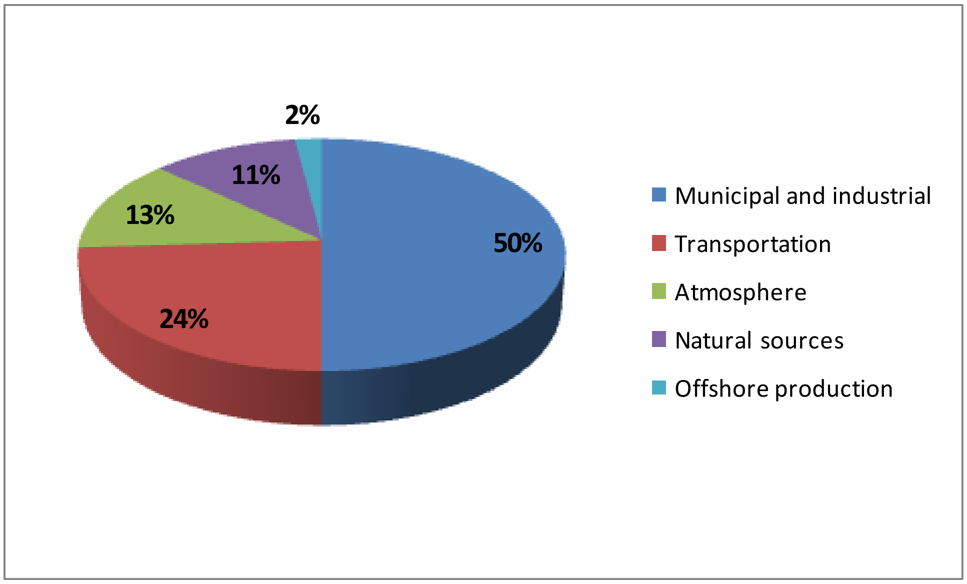


Figure 3 - Estimated Inputs of Oil into the Ocean

The figure shows that the largest contributor to marine oil pollution is from municipal and industrial activities, including urban runoff. Transportation of petroleum is the next largest contributor, including operational discharges and tanker-spills. This is followed by the atmospheric, natural sources and offshore production, respectively.

1.2 Oil-spill Causes

There are a variety of causes of oil-spills that may occur as a result of petroleum production and transportation. The exact causes of a spill can be exceedingly technical and lengthy; therefore the causes will only be explored here in a general sense. The causes of oil-spills are largely dependent upon the type of spill in question. Section 1.2.1 deals with spills from drilling incidents, Section 1.2.2 deals briefly with spills from pipeline transportation, and Section 1.2.3 deals with spills from oil-tanker operations.

1.2.1 Drilling Incidents

Accidents during drilling can be categorized into two groups: routine operations and catastrophic incidents. Both are related to blowouts. A blowout is a continuous release of hydrocarbons from a well as a result of unanticipated high pressures and the inability to contain the flow of hydrocarbons. Blowouts are controlled by large valve devices known as blowout preventers (BOP's) mounted at the top of a wellhead. In the event of a kick or uncontrolled flow the BOP should activate to shut off all flow from the well. The success of the BOP will determine the significance of the event. Providing the BOP is triggered and performs its job, the flow will be halted. Once well-control is gained, the fluid density in the well can be increased to regain well-control. This may amount to a small spill and will be categorized within routine operations. If the BOP fails to activate, Well-control cannot be regained, resulting in intense prolonged gushing and large spill volumes.

In the petroleum industry, an important distinction is made between two stages of drilling: exploratory drilling and field development drilling. Exploratory drilling involves the process of looking for oil in undrilled reservoirs. During this stage, knowledge of the geological and depositional environment is speculative, leading to further uncertainty while drilling. For field development wells, much more is known concerning the drilling and geological expectations. This results in reduced occurrences of unexpected conditions. Whereas blowouts are more pronounced during drilling operations, they may also occur in other stages of a well's life. This includes production, workovers and well completion activities.

Blowouts are caused by formation kicks. When drilling, downhole fluid pressure is controlled via balancing the hydrostatic pressure of the fluid column against the formation or reservoir pressure. In safe drilling practices, the hydrostatic pressure is kept higher than the formation pressure, resulting in an overbalanced scenario. If a well is drilled into an unexpected high-pressure zone, the formation pressure may be greater that the hydrostatic pressure, resulting in an underbalanced scenario. This pressure differential allows formation fluids to enter the wellbore, which is known as a kick. Kicks can also occur due to a loss of drilling fluid to the formation via a thief zone. Figure 4 shows typical hydrostatic gradients and how abnormal formation pressures lead to underbalanced scenarios.

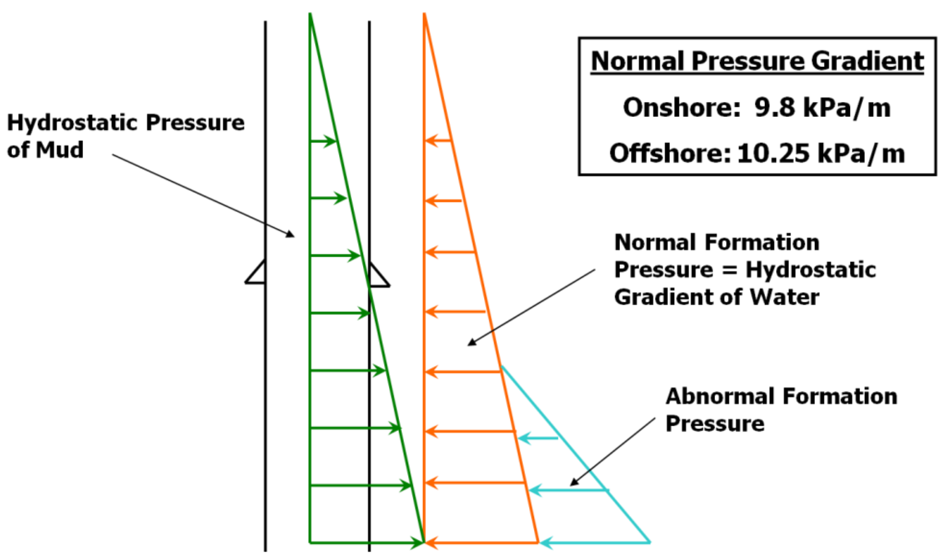


Figure 4 - Normal Formation Pressure versus Abnormal Formation Pressure

Source: (C-NLOPB, 2010)

Once hydrocarbon fluids enter the wellbore they quickly rise to the surface due to density difference between the fluids and fluid compressibility. To prevent a blowout the BOP must be activated to effectively shut-in all wellbore flow. The weight of the drilling mud must then be increased and circulated through the wellbore until well-control is regained in an overbalanced scenario.

Whereas kicks are the initiating factor for blowouts, if proper well-control systems are in place and effective safety regulations are followed, they should rarely result in blowouts. Root causes of blowouts often relate back to inadequate drilling procedures, poor judgment, inadequate maintenance, operator error and equipment failure.

The Newfoundland and Labrador offshore has additional concerns for both blowouts and batch-spills as a result of the harsh weather environment. In particular, concerns from sea-ice and icebergs heavily influence the design of the offshore structures. The prevalence of sea-ice and icebergs uniquely affect the Newfoundland and Labrador offshore unlike any other area worldwide. Their potential interactions, both through direct collisions or scouring, represent an additional risk to operations and increase the likelihood of potential spills.

1.2.2 Pipeline Transportation Incidents

Oil-spills also occur during pipeline transportation, both on land and on the seabed. These can vary from small leaks over time to large catastrophic ruptures. The causes of these spills are often related to material defects, corrosion and poor maintenance, but can also be caused by collisions with ship anchors or trawling vessels (Hawboldt, 2010). Tectonic activity may also be of concern. Offshore pipelines are common in many areas of the world, including the Baltic Sea, Russia and the Gulf of Mexico. There are no oil or gas pipelines in the Newfoundland and Labrador offshore.

1.2.3 Tanker-spill Incidents

Oil-spills during storage and transportation are referred to as batch-spills. In these incidents, a short term or instantaneous volume of oil is released into the environment. The spill volume is limited to the capacity of the vessel, line or transportation device. This category includes incidents associated with production operations where oil is stored or handled, transportation of oil from a production facility to tankers, or spills from ocean-going tankers while transporting the oil from the production facility to ports. The volumes associated with batch-spills are typically much smaller than uncontrolled blowouts, but their impact can be significant. This is especially evident when large tanker-spills occur close to shore where the environmental sensitivity is increased.

There are numerous causes of batch-spills. Specific and root causes vary for each individual case, but for the purposes of a general analysis, the causes are categorized into general groups. Tanker-spills, the largest source of batch-spills, are typically caused by loading and discharge issues, collisions, hull failures or structural flaws, groundings, fire and explosions, bunkering, other operations or unknown causes (Huijer, 2005). Figure 5 through Figure 7 show the breakdown in spill causes for various spill-size ranges.

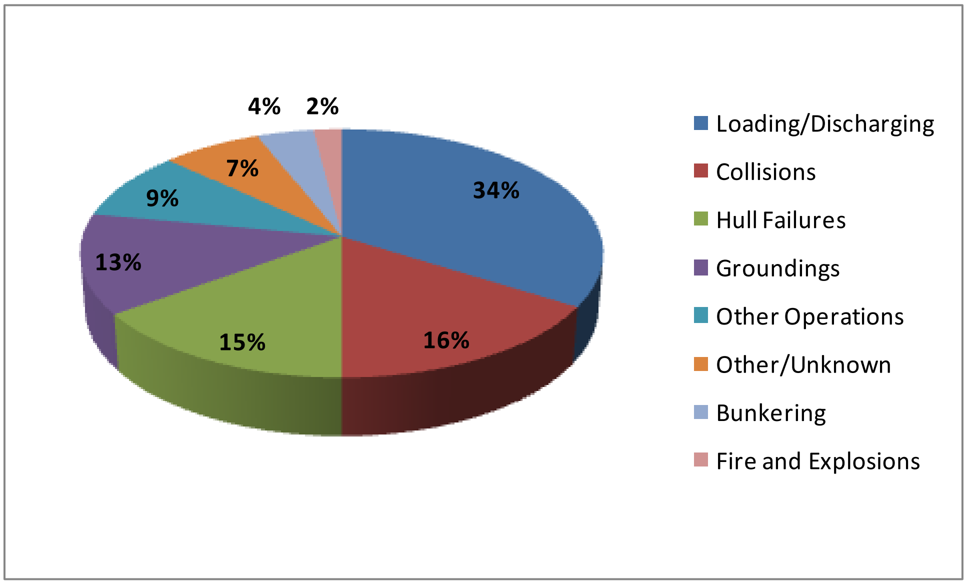


Figure 5 - Causes of Tanker-spills < 7 tonnes (1995-2004)

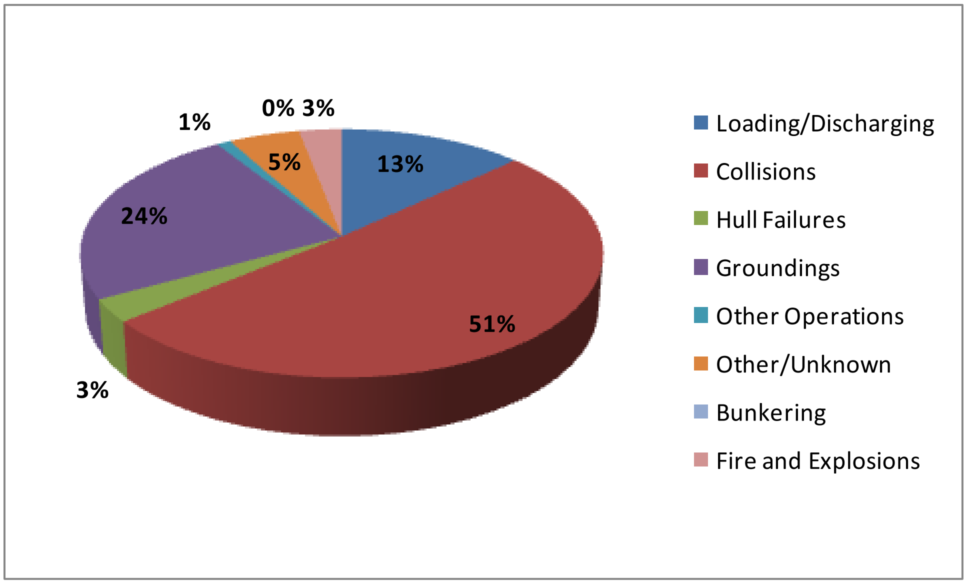


Figure 6 - Causes of Tanker-spills 7-700 tonnes (1995-2004)

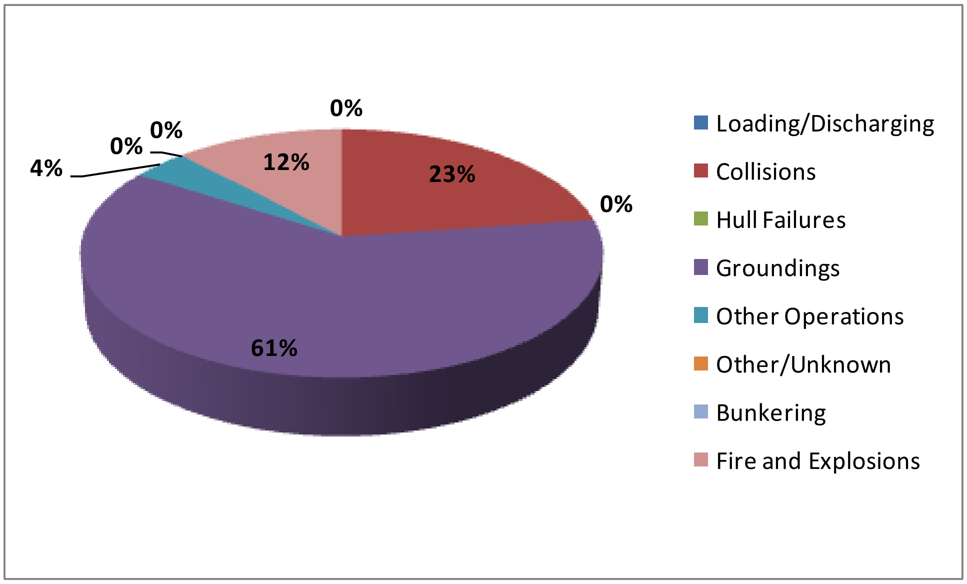


Figure 7 - Causes of Tanker-spills > 700 tonnes (1995-2004)

For small spills, all causes show some importance with loading and discharging being the main contributing factor. The largest spills (greater than 700 tonnes) are caused predominately by groundings and collisions. Note that these are the general causes of the spill occurrence, but the root causes may stem from other issues, including poor maintenance, inadequate management and poor safety procedures.

1.2.4 Summary

Table 3 provides a list of the twelve largest spills since 1967. Note that the majority are from tanker related incidents.

Table 3 - Twelve Largest Oil-spills since 1967

Rank	Name	Location	Quantity (millions of gallons)	Date	Note
1	Gulf War Oil-spill	Persian Gulf, Kuwait	450 (380-520)	January 19, 1991	Act of war
2	Macondo Oil-spill	Gulf of Mexico, United States	205	April 20, 2010	Offshore blowout
3	IXTOC 1	Bay of Campeche, Mexico	140	June 3, 1979	Offshore blowout
4	Atlantic Empress	Off Trinidad and Tobago	90	July 19, 1979	Tanker collision
5	Fergana Valley	Uzebekistan	88	March 2, 1992	Inland blowout
6	Kolva River	Kolva Rover tributary, Russia	84	September 8, 1994	Pipeline leak
7	Nowruz Oil Field	Persian Gulf, Iran	80	February 10, 1983	Tanker-platform collision leading to blowout
8	Castillo de Bellver	Off Saldanha Bay, South Africa	79	August 6, 1983	Tanker incident
9	Amoco Cadiz	Portsall, France	69	March 16, 1978	Tanker incident
10	ABT Summer	Off Angola	66 (51-81)	May 28, 1991	Tanker incident
11	M/T Haven	Genoa, Italy	45	April 11, 1991	Tanker incident
12	Odyssey	Off Nova Scotia, Canada	41	November 10, 1988	Tanker incident
NOTES:					
The Lakeview Gusher, occurring in Kern County, California, United States from March 14th, 1910 to September 1911 is considered one of the largest spills in history, with a total spillage estimated at 380 million gallons.					
Spill volume and rankings may vary dependent upon source.					
There are 42 US gallons in 1 barrel of oil, or 0.0238 barrels of oil per gallon.					

Source: Modified from (Pollution Issues, 2010) using additional information from (National Oceanic and Atmospheric Administration, 1992), (Epic Disasters, 2010) and (Bazilescu & Lyhus, 1996).

1.3 Blowout Frequency

Reliable data for oil-spills resulting from blowouts is difficult to obtain. A comprehensive database has been established by SINTEF, an independent non-commercial research organization in Scandinavia. The database includes information on 574 offshore blowouts/well releases that have occurred since 1955, as well as exposure data for the Gulf of Mexico, United Kingdom Outer Continental Shelf and the North Sea (SINTEF, 2010). Unfortunately access to the database is restricted to the project sponsors, namely Statoil, Total E&P Norge, Shell Research Limited, BP Norge, Safetec A/S, Scandpower Risk Management AS, DNV, Lilleaker Consulting AS, EniNorge AS, ConohoPhillipsNorge and BHP Billiton.

However, some statistics from the SINTEF database are available through various publications. A recent report by the International Association of Oil and Gas Producers deals strictly with summarized data from the SINTEF database. The report examines blowout frequencies for the purposes of performing risk assessments. The summarized tables consider various stages in well operations. As well, the frequencies are expressed for wells of North Sea standard and not of North Sea standard. The North Sea standard is defined as an operation with BOP installed including shear ram and a two-barrier principle followed (BOP and overbalanced drilling fluid) (International Association of Oil and Gas Producers, 2010).

Table 4 and Table 5 are reproductions of the blowout frequency tables from this report. Note that a well release is an incident when hydrocarbons are released but quickly stopped by the use of barrier systems, but a blowout is when these barriers fail to stop the flow.

The International Association of Oil and Gas Producers' report assumes that these frequencies can be directly applied for well operations worldwide, both offshore and onshore. The far right columns of both tables indicate the fraction of subsea wells encompassed in the frequency calculation, as estimated by Det Norske Veritas (DNV). The unit of frequency depends upon the operation. It may be presented as per drilled well, per operation or per well year. Several of the frequencies are equal to zero. This indicates that over the period studied, blowouts or well releases did not occur during these specific operations.

The exact procedure used to determine these frequencies are not disclosed in the report. The analysis is performed and updated annually by SINTEF. The historical period analyzed begins on January 1, 1980 and ends on January 1, 2005 for the data provided. In general, frequency is just a simple calculation dividing the number of incidents by the number of trials. This may be modified to incorporate time, as with the production wells, by performing the analysis on a per well year basis. It is important to note that SINTEF does adjust these figures by the elimination of irrelevant incidents and by applying corrections due to trends over time (International Association of Oil and Gas Producers, 2010).

The frequency of a blowout or well release can be determined for a production field via superposition. The frequencies for particular events over the course of a project can be added together to determine the cumulative frequency.

Table 4 - Blowout and Well Release Frequencies for Offshore Operations of North Sea Standard

Operation	Category	Frequency				Fraction Subsea
		Average	Gas	Oil	Unit	
Exploration drilling, shallow gas	Topside blowout	-	6.0×10^{-4}	-	Per drilled well	
	Diverted well release	-	8.3×10^{-4}	-	Per drilled well	
	Well release	-	9.3×10^{-5}	-	Per drilled well	
	Subsea blowout	-	9.8×10^{-4}	-	Per drilled well	
Development drilling, shallow gas	Topside blowout	-	4.7×10^{-4}	-	Per drilled well	
	Diverted well release	-	6.5×10^{-4}	-	Per drilled well	
	Well release	-	7.3×10^{-5}	-	Per drilled well	
	Subsea blowout	-	7.4×10^{-4}	-	Per drilled well	
Exploration drilling, deep (normal wells)	Blowout	3.1×10^{-4}	3.6×10^{-4}	2.5×10^{-4}	Per drilled well	0.39
	Well release	2.5×10^{-3}	2.9×10^{-3}	2.0×10^{-3}	Per drilled well	0.39
Exploration drilling, deep (HPHT[1] wells)	Blowout	1.9×10^{-3}	2.2×10^{-3}	1.5×10^{-3}	Per drilled well	0.39
	Well release	1.6×10^{-2}	1.8×10^{-2}	1.2×10^{-2}	Per drilled well	0.39
Development drilling, deep (normal wells)	Blowout	6.0×10^{-5}	7.0×10^{-5}	4.8×10^{-5}	Per drilled well	0.33
	Well release	4.9×10^{-4}	5.7×10^{-4}	3.9×10^{-4}	Per drilled well	0.33
Development drilling, deep (HPHT wells)	Blowout	3.7×10^{-4}	4.3×10^{-4}	3.0×10^{-4}	Per drilled well	0.33
	Well release	3.0×10^{-3}	3.5×10^{-3}	2.4×10^{-3}	Per drilled well	0.33
Completion	Blowout	9.7×10^{-5}	1.4×10^{-4}	5.4×10^{-5}	Per operation	0
	Well release	3.9×10^{-4}	5.8×10^{-4}	2.2×10^{-4}	Per operation	0
Wirelining	Blowout	6.5×10^{-6}	9.4×10^{-6}	3.6×10^{-6}	Per operation	0
	Well release	1.1×10^{-5}	1.6×10^{-5}	6.1×10^{-6}	Per operation	0
Coiled tubing	Blowout	1.4×10^{-4}	2.0×10^{-4}	7.8×10^{-5}	Per operation	0
	Well release	2.3×10^{-4}	3.4×10^{-4}	1.3×10^{-4}	Per operation	0
Snubbing	Blowout	3.4×10^{-4}	4.9×10^{-4}	1.9×10^{-4}	Per operation	0
	Well release	1.8×10^{-4}	2.6×10^{-4}	1.0×10^{-4}	Per operation	0
Workover	Blowout	1.8×10^{-4}	2.6×10^{-4}	1.0×10^{-4}	Per operation	0
	Well release	5.8×10^{-4}	8.3×10^{-4}	3.2×10^{-4}	Per operation	0
Production wells (excluding external causes)	Blowout	9.7×10^{-5}	1.8×10^{-5}	2.6×10^{-6}	Per well year	0.125
	Well release	1.1×10^{-5}	2.0×10^{-5}	2.9×10^{-6}	Per well year	0.125
Production wells, external causes	Blowout	3.9×10^{-4}	3.9×10^{-5}	3.9×10^{-5}	Per well year	0.125
	Well release	-	-	-	Per well year	-
Gas injection wells	Blowout	-	1.8×10^{-5}	-	Per well year	0.125
	Well release	-	2.0×10^{-5}	-	Per well year	0.125
Water injection wells	Blowout	2.4×10^{-4}	-	-	Per well year	0.125
	Well release	-	-	-	Per well year	-

Source: (International Association of Oil and Gas Producers, 2010)

[1]HPHT (High pressure, high temperature)

Table 5 - Blowout and Well Release Frequencies for Offshore Operations not of North Sea Standard

Operation	Category	Well Type	Frequency		Fraction Subsea
Exploration drilling, shallow gas	Blowout (surface flow)	Appraisal	$1.3x10^{-3}$	Per drilled well	0.59
		Wildcat	$1.9x10^{-3}$	Per drilled well	0.59
	Blowout (underground flow)	Appraisal	0	Per drilled well	0
		Wildcat	0	Per drilled well	0
	Diverted well release	Appraisal	$3.2x10^{-4}$	Per drilled well	0
		Wildcat	$9.3x10^{-4}$	Per drilled well	0
	Well release	Appraisal	$3.2x10^{-4}$	Per drilled well	1
		Wildcat	$2.7x10^{-4}$	Per drilled well	1
Development drilling, shallow gas	Blowout (surface flow)	-	$9.6x10^{-4}$	Per drilled well	0.18
	Blowout (underground flow)	-	$4.4x10^{-5}$	Per drilled well	0
	Diverted well release	-	$7.0x10^{-4}$	Per drilled well	0
	Well release	-	$8.8x10^{-5}$	Per drilled well	0
Exploration drilling, deep	Blowout (surface flow)	Appraisal	$1.4x10^{-3}$	Per drilled well	0.41
		Wildcat	$1.7x10^{-3}$	Per drilled well	0.41
	Blowout (underground flow)	Appraisal	0	Per drilled well	-
		Wildcat	$9.3x10^{-4}$	Per drilled well	0.17
	Diverted well release	Appraisal	0	Per drilled well	-
		Wildcat	0	Per drilled well	-
	Well release	Appraisal	0	Per drilled well	1
		Wildcat	0	Per drilled well	1
Development drilling, deep	Blowout (surface flow)	-	$3.5x10^{-4}$	Per drilled well	0.14
	Blowout (underground flow)	-	$1.3x10^{-4}$	Per drilled well	0
	Diverted well release	-	0	Per drilled well	-
	Well release	-	$2.2x10^{-4}$	Per drilled well	0.25
Completion	Blowout (surface flow)	-	$4.6x10^{-4}$	Per completion	0
	Blowout (underground flow)	-	0	Per completion	0
	Diverted well release	-	$3.1x10^{-4}$	Per completion	0
	Well release	-	0	Per completion	0
Production	Blowout (surface flow)	-	$3.3x10^{-5}$	Per well year	0.43
	Blowout (underground flow)	-	$4.7x10^{-6}$	Per well year	0
	Diverted well release	-	0	Per well year	0
	Well release	-	$9.5x10^{-6}$	Per well year	0
Workover	Blowout (surface flow)	-	$1.0x10^{-3}$	Per workover	0.05
	Blowout (underground flow)	-	0	Per workover	0
	Diverted well release	-	0	Per workover	0
	Well release	-	$8.5x10^{-4}$	Per workover	0
Wireline	Blowout (surface flow)	-	$1.1x10^{-5}$	Per wireline job	0
	Blowout (underground flow)	-	0	Per wireline job	0
	Diverted well release	-	0	Per wireline job	0
	Well release	-	$1.1x10^{-5}$	Per wireline job	0

Source: (International Association of Oil and Gas Producers, 2010)

It is important to note that these calculations are based solely upon historic data and are not a true or reliable measure for the probability of a blowout. The numbers have a purpose in providing a feeling for likelihood, but more accurate measures should be taken to determine the risk for a particular well or field.

Nonetheless, comparing the data in the two tables, there is a clear reduction in blowout frequency for operations following the North Sea standard versus those that do not. In all but a few categories, the blowout frequency for the North Sea Standard is an order of magnitude less than for the non-North Sea Standard, and in the few remaining categories, the North Sea frequency is comparable.

1.4 Tanker-spill Frequency

There is a wealth of publicly available data concerning Batch-spills from tankers. This data include historical figures concerning the number of spills and the quantity released. As with the causes of tanker-spills in Section 1.2.3, the data is typically broken down into categories based on size. Figure 8 displays the annual number of reported spills from tankers for spills greater than 7 tonnes. This is divided into spills from 7 to 700 tonnes and spills greater than 700 tonnes. The data are provided by the International Tanker Owner Pollution Federation (ITOPF).

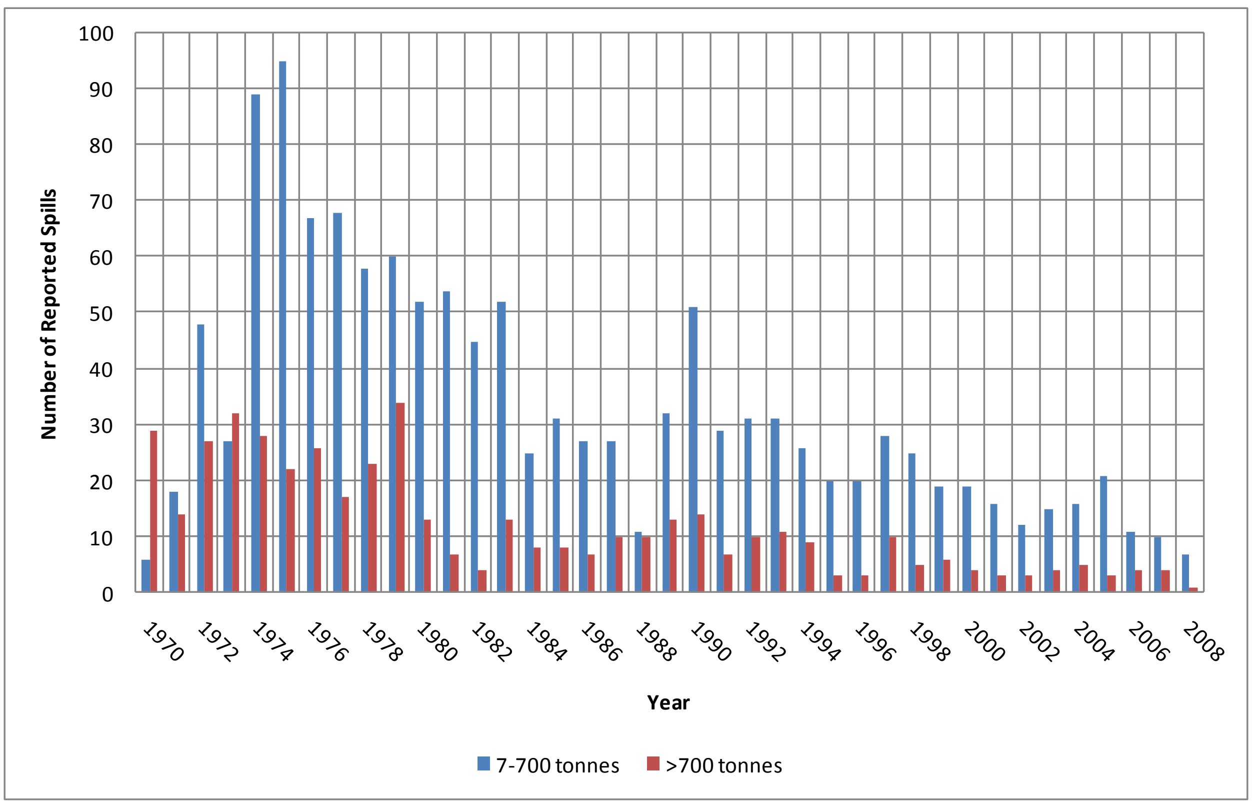


Figure 8 - Annual Number of Reported Spills from Tankers (> 7 tonnes)

Source: Modified from (ITOPF, 2008)

The plot above shows a significant decrease in the number of spills since 1970. This applies for both spills on the order of 7 to 700 tonnes as well as spills greater than 700 tonnes. The ITOPF concludes that this reduction is due to the strengthening of international laws as well as various national regulations to enforce stricter measures on oil pollution at sea (ITOPF, 2008).

Figure 9 presents the quantity of oil released as a result of accidental spills from tankers.

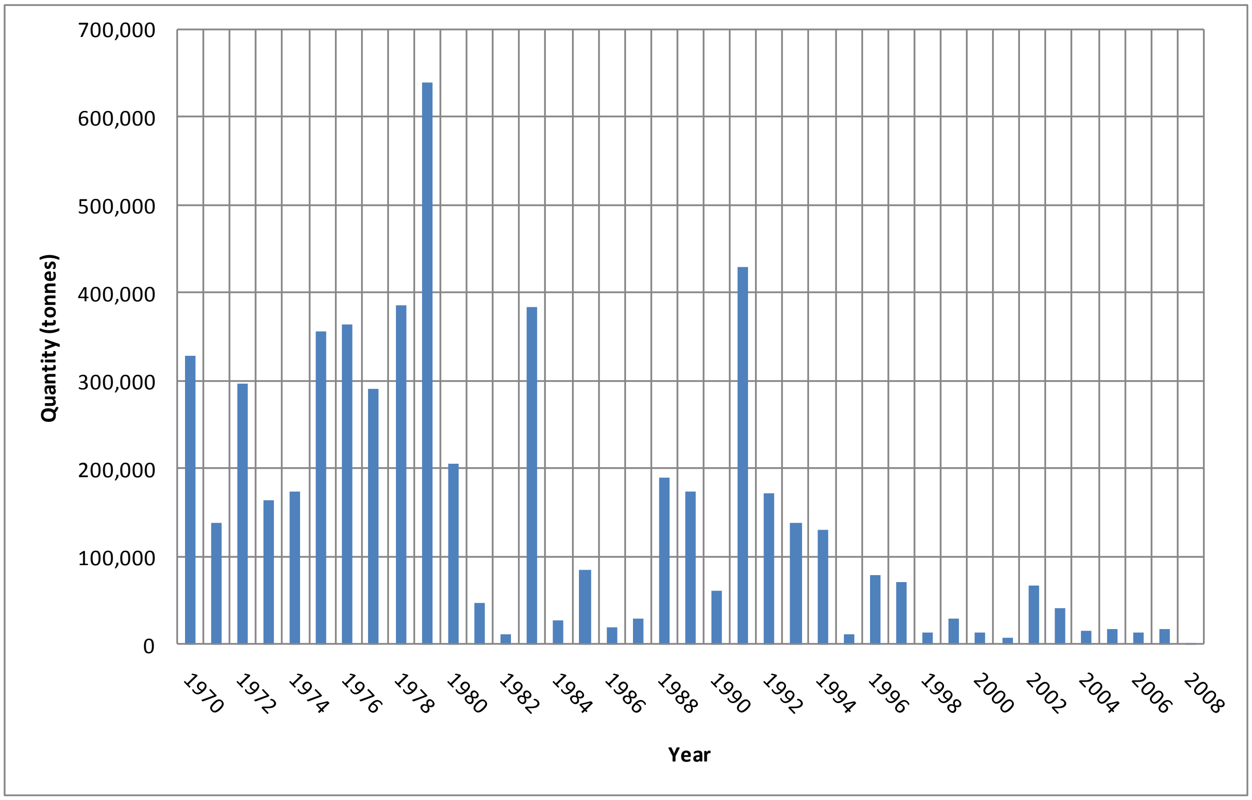


Figure 9 - Annual Quantity of Accidental Oil-spilled from Tankers

Source: Modified from (ITOPF, 2008)

The downward trend referenced in the number of spill data is still apparent with respect to the quantity spilled, but the trend is much more erratic. This can be attributed to the fact that a few very large spills are responsible for a high percentage of the total oil-spilled. Therefore the figures for a particular year may be severely distorted by a single large spill. Large spills responsible for peaks in the data above include the 1979 *Atlantic Empress* (287 000 tonnes), the 1983 *Castillo de Bellver* (252 000 tonnes) and the 1991 *ABT Summer* (260 000 tonnes).

Tanker-spill frequencies can be determined in the same manner as the process for blowout frequencies explained in Section 1.3. This is performed by analyzing historical data to determine how often spills occur for particular situations. This type of analysis has been performed by S.L. Ross Environmental

Research Ltd. in examining the likelihood of a spill in Placentia Bay and other areas of high tanker traffic along Newfoundland's south coast (S.L. Ross Environmental Research Ltd., 2007). The south coast has significant tanker traffic due to the import of crude to the local refinery, exporting refined products, shuttle tankers from the Transshipment Terminal, international traffic bypassing and several additional reasons.

The south coast risk assessment used historical data from both the local area and international numbers to perform the frequency analysis. Tables 6 and 7 provide the spill-frequency data for the south coast of Newfoundland, first as an annual predicted spill frequency, and second as the estimated "years per spill" (i.e., the inverse of the frequency). The figures are based upon the annual number of trips and the cargo size that is carried (S.L. Ross Environmental Research Ltd., 2007). For further information regarding this analysis please refer to the South Coast Risk Assessment Synopsis Report.

Table 6 - Predicted Annual Spill Frequency for South Coast Newfoundland

Spill size, barrels	**Inner Placentia Bay**		**Outer Placentia Bay and Placentia Bay South**		**Cabot Strait**	**St. John's**	
	Crude	**Refined Product**	**Crude**	**Refined Product**	**Refined Product**	**Crude**	**Refined Product**
1 to 49	9.55×10^{-1}	7.44×10^{-1}	2.21×10^{-1}	1.83×10^{-1}	9.41×10^{-3}	1.87×10^{-3}	3.64×10^{-4}
50 to 999	1.20×10^{-1}	1.60×10^{-1}	2.79×10^{-2}	3.95×10^{-2}	2.03×10^{-3}	2.35×10^{-4}	7.83×10^{-5}
1000 to 9999	3.77×10^{-2}	3.04×10^{-2}	4.99×10^{-3}	6.90×10^{-3}	3.54×10^{-4}	4.22×10^{-5}	1.37×10^{-5}
10000 to 99999	8.69×10^{-3}	1.16×10^{-3}	4.99×10^{-3}	7.44×10^{-4}	3.82×10^{-5}	4.22×10^{-5}	1.48×10^{-6}
100000 to 199999	1.30×10^{-3}	1.02×10^{-3}	4.47×10^{-4}	3.90×10^{-4}	2.00×10^{-5}	3.77×10^{-6}	7.74×10^{-7}
> 200000	4.49×10^{-4}	5.18×10^{-4}	1.66×10^{-3}	1.95×10^{-4}	1.00×10^{-5}	1.40×10^{-5}	3.87×10^{-7}
Total (spill of any size)	1.13	9.37×10^{-1}	2.61×10^{-1}	2.31×10^{-1}	1.19×10^{-2}	2.21×10^{-3}	4.59×10^{-4}

Source: (S.L. Ross Environmental Research Ltd., 2007)

Table 7 - Predicted Spill Frequency for South Coast Newfoundland, years per spill

Spill size, barrels	Inner Placentia Bay		Outer Placentia Bay and Placentia Bay South		Cabot Strait	St. John's	
	Crude	**Refined Product**	**Crude**	**Refined Product**	**Refined Product**	**Crude**	**Refined Product**
1 to 49	1.0	1.3	4.5	5.5	106	535	2,750
50 to 999	8.3	6.3	36	25	493	4260	12,800
1000 to 9999	26	33	200	145	2,820	23,700	73,000
10000 to 99999	115	862	200	1,340	26,200	23,700	676,000
100000 to 199999	769	980	2,240	2,560	50,000	265,000	1,290,000
> 200000	2,227	1,930	602	5130	100,000	71,400	2,580,000
Total (spill of any size)	0.9	1.1	3.8	4.3	84	453	2,180

Source: (S.L. Ross Environmental Research Ltd., 2007)

2.0 Oil-spill Prevention

The best method of defense from an oil-spill is prevention, which is the primary focus of operations in the Newfoundland and Labrador offshore. The operators, C-NLOPB and Transport Canada place considerable emphasis into designing safe and environmentally responsible operations to minimize the likelihood of a spill. Spill-prevention measures are incorporated throughout all aspects of operation, including exploration, drilling, project development, design and operations. The measures are of a world-class standard and are for the sole purpose of maintaining safety and protecting the environment (C-NLOPB, 2010).

Spill-prevention measures are vast and cover a wide range of areas. For clarity, these measures are broken down into six areas: regulations governing the operations, wellbore design, well-control, facility design, facility operations and safety culture. General information regarding wellbore design, well-control and safety culture is provided in the following sections. Newfoundland and Labrador specific information regarding regulations, facility design and facility operation are provided throughout Section 3 of the main document.

2.1 Well Design

The design of a well is an iterative process that involves many parties in a petroleum operation. Initially the reservoir department will select a reservoir target along with various objectives. This will be forwarded to the drilling and completions department to design a well capable of reaching the target and meeting the setout objectives. The facility and operations departments may review the plans and suggest changes to the design. Service companies may also review the well program to ensure use of specialized equipment is possible in the given design. This process continues with continuous revisions from each unit until a consensus design is finalized. Following this, a well program is generated for the operations team to follow in the well-construction process (Husky Energy, 2010). This program and all aspects of the proposed well are reviewed by the C-NLOPB via an Approval to Drill a Well (ADW).

Each section of the well program is designed such that risk is minimized. The primary method of well-control is the hydrostatic pressure afforded by the fluid column in the well. The BOP acts as a secondary method of well-control. This is known as the two barrier system.

2.2 Well-control

In the process of drilling, well-control processes and systems are used by the operators with focus on blowout prevention. The goal of well-control processes is to control well kicks, which are the unexpected inflow of production fluids into the wellbore. These kicks are the precursors to blowouts if not properly contained.

For a kick to lead to a blowout, a chain of successive failures in the well-control process would have to transpire ahead of the ultimate failure. The well-control chain is comprehensive, involving aspects of reservoir conditions, geology, drilling, well design and safety. Figure 10 outlines an overview of the standard well-control process.

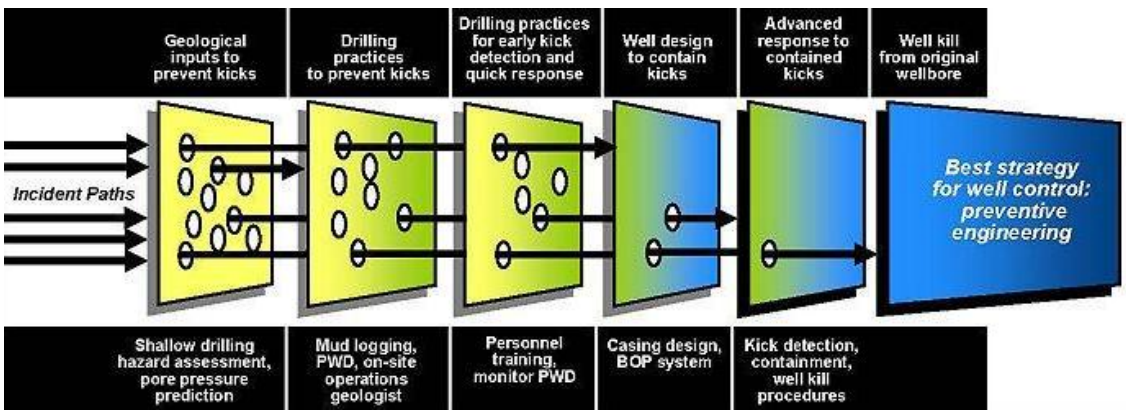


Figure 10 - Standard Well-control Process

Source: (CAPP, 2010)

In the well-control process, numerous steps are taken to avoid kicks leading to blowouts. On a geological level, much effort is placed into understanding the formation. Work from both geologists and reservoir engineers look to determine the pressure and temperature environment of the target formation. Shallow seismic surveys are also performed to assess shallow drilling hazards, as well as an evaluation of the entire well survey to minimize risk associated with certain geological formations.

During the drilling of a well, safe drilling practices are essential to maintain safe operations and avoid kicks. This includes mud logging, maintaining overbalanced pressure while drilling and having qualified engineers, geologists, technicians and other workers on staff to constantly monitor the drilling process. Early kick detection and response is also an essential element of the drilling process. This involves operator training to be able to effectively respond in the event of a kick, as well as monitoring both pressure and flow while drilling to know exactly when a kick occurs. This ensures the maximum amount of response time for operators to react and control the kick before it can escalate into a blowout.

Should a kick occur, effective well design should contain the influx. This includes the entire well design from casing and cementing to the detailed BOP design. Several levels of well-control are incorporated into an effective well design. The primary level of well-control is the hydrostatic pressure exerted by the drilling fluid. In the Newfoundland and Labrador offshore, all wells must be drilled overbalanced. This means the hydrostatic pressure of the drilling mud in the wellbore must be greater than the expected pressure of the formation. Most reservoirs in the Newfoundland and Labrador offshore are normally pressured. This means the pressure increases with depth at the same rate as if it were water alone. The gradient of seawater is approximately 10.25 kPa/m. Therefore, as long as the density of the drilling mud is greater than the density of seawater, a blowout should not occur. Typical pressure gradients while drilling at the Hibernia platform often exceeds 14.5 kPa/m. This is a significantly overbalanced scenario that considerably reduces the risk of a blowout (HMDC, 2010).

Mud engineers and crew constantly monitor the weight of drilling fluid and mud levels in various tanks during drilling or tripping of pipe. Any drop in this level would indicate lost circulation to a formation. The rate of mud returns is also closely monitored to match the rate that it is being pumped down-hole. If the rate of mud returns is slower than expected, then a certain amount of the mud is being lost to a thief zone. In the case of the over-pressured gas pocket, an increase in mud returns would be noticed when the formation gasses push mud to the surface at a rapid rate.

Kicks often occur as a result of entering an unexpected over-pressured formation. There are no over-pressured formations at the three production fields in the Newfoundland and Labrador offshore, but over-pressured formations have been experienced in several exploration wells in the region. In these circumstances, the pressure has been greater than the hydrostatic pressure afforded by the fluid column, resulting in kicks. Other contributions for loss of primary well-control included failure to keep the hole full, loss of circulation and swabbing and/or piston action from pulling and running tools.

Once a kick has occurred, the primary level of well-control has failed and secondary levels must take over. The secondary level of well-control is the BOP. The BOP is a series of large valves deigned to cut off all flow from a well in the event of a kick. Depending upon the design, the BOP may have several methods of cutting off the flow as well as several activating devices.

There are only two levels of well-control while drilling; the fluid column and the BOP. Should both methods fail, well-control is lost and a potentially hazardous scenario is inevitable. These events should be rare providing effective well-control procedures are followed.

Providing a kick is contained by the BOP, efforts can be made to regain control of the well. This includes cycling the drilling mud for the entire wellbore and increasing the density of the drilling fluid. Once a kick is detected, the first step is to activate the BOP and close in the well. The drilling crew will then look to circulate a heavy kill fluid to increase the hydrostatic pressure and regain well-control. During this process, fluids will be continuously circulated to remove hydrocarbons in a controlled manner. Care must be taken to prevent gas from accelerating up the wellbore too quickly as a result of expansion.

Loss of secondary well-control may be a result of:

- Failure to install, check or operate BOP equipment properly
- Failure to detect a kick and to initiate kick-control operations quickly
- Mechanical failure of BOP equipment
- Failure of casing
- Failure of well-head equipment
- Failure of the drilled formation or the cement bond around a casing string

Experience has shown that the majority of blowouts are caused by errors made by drilling-rig personnel. Therefore, well-control training and monitoring are essential elements in the prevention of a blowout.

If all well-control efforts fail, a blowout will occur. Blowouts can be extremely dangerous to workers aboard the drilling platform/vessel due to the high bottom-hole pressure leading to a rapid influx of fluid into the well. Gas contained within the fluids will expand rapidly as it travels up the wellbore as a result of compressibility. The fluid momentum leads to extremely high forces. The force may be strong enough to eject the entire drill string and cause extensive damage to the rig. Once at the surface, hydrocarbon gas may find an ignition source, leading to an explosion.

Current practice in the Norwegian and Newfoundland and Labrador offshore now refers to well-control barriers in terms of control envelopes. This terminology looks to distinguish between well-control elements and groups of elements. For a well-control envelope to be successful, all composing elements must also be successful. Therefore for effective well-control, two layers of well envelopes should be maintained, which consist of several more elements. Table 8 outlines the well envelopes/barriers necessary while drilling, with visual reference provided in Figure 11.

Table 8 - Well-control Barriers (Envelopes)

Well Barrier Level (Envelope)	Necessary Elements
Primary	Fluid column
Secondary	Casing cement
	Casing
	Wellhead
	High pressure riser
	Drilling BOP

Source: (C-NLOPB, 2010)

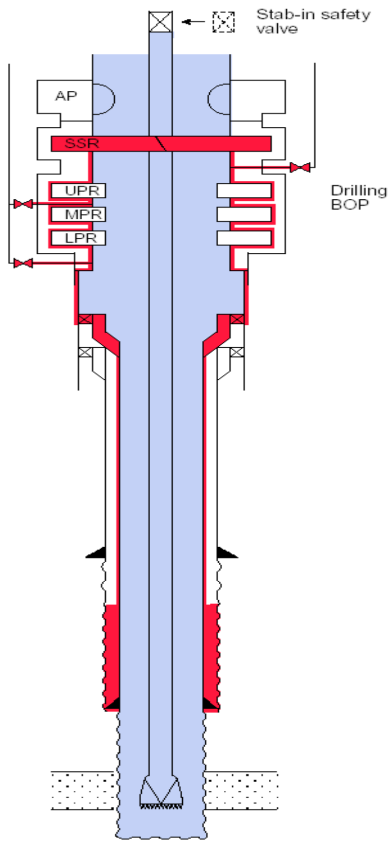


Figure 11 - Well-control Barriers

Source: (C-NLOPB, 2010)

For all kicks that have occurred in the Newfoundland and Labrador offshore, effective well-control procedures have been utilized, the BOP's have worked as designed, and potentially dangerous situations have been avoided.

2.2.1 Well-control and Contingency Planning

As drilling activities moved farther offshore into deeper water, the operations have become more complex, and so to have the problems associated with well-control. Contingency plans are designed to reduce the impact of a blowout or well-control issues. They facilitate blowout intervention and minimize danger to life and the environment. An effective contingency plan identifies the basic requirements of a well-control scenario.

The five key areas of crisis management teams responding to a serious well-control situation are:

- Corporate response - both internal and external, including government regulatory agencies and the media
- Safety - the safety of all people and equipment
- Environmental - spill-response, containment, regulatory reporting and clean-up
- Drilling and workover operations - well-control and relief-well drilling operations
- Ongoing non-crisis activity - reallocation of company personnel and equipment

The operator should design a contingency plan that outlines what to do and who will do it in the event of a problem. This provides the operator the opportunity to design a plan in a calm atmosphere with as much forethought and engineering background as possible so that he/she is less likely to make erroneous decisions and can reduce response time in an emergency situation. All contingency plans should contain the following:

1) Well-control management: Identify a response organization that will assist the operator in an emergency.

2) Risk assessment: Gauge the probability of a well-control event, the area that may be impacted, evaluate the consequences of a loss in well-control and create a risk mitigation plan.

3) Contractors, equipment and services: Availability of firefighting, pollution and spill containment equipment, fabrication of parts, and associated transportation should be documented in the plan.

4) Well-control procedures and technical data: Reference material for intervention and relief-well fighting including conventional well-control procedures, relief-well strategy and blowout intervention techniques should be part of the plan.

5) Administrative considerations: Before an incident occurs, an event-control centre should be designed and vendor and contractor pre-qualifications and contacts should be in place. Well-

control insurance policy information, legal procedures and documentation, record keeping and auditing requirements are also important.

Surface intervention usually involves capping and fluid dynamics. Subsurface intervention may involve engineering analysis, snubbing, coil tubing and fluid dynamics. Relief-wells are another option if the others fail. A relief-well requires knowledge of geology, drilling, completions, logging, and blowout management.

Contingency planning is extremely important and must be reconsidered on a regular basis to ensure new technological advancements are incorporated. Well-control will continue to evolve with industry and the leaders will be those who are prepared, organized and in control of the situation (Cudd & Goodman, 1995).

2.2.2 Relief-wells

The objective of a relief-well is to intercept, communicate and control a blowout if all else fails. A successful relief-well will overcome unknowns in the position of the blowout well, also known as the ellipse of uncertainty. On occasion, the uncertainties are large enough that intercepting the blowout well with the relief-well would be impossible unless the blowout position can be accurately mapped relative to the relief-well. Distance and direction must be determined and ranging must be performed. Upon determining the relative position, relief-well trajectory can be modified in order to make the intercept.

As mentioned earlier, if a well clearly cannot be capped, the decision is simple - drill a relief-well.

Although the necessity for relief-wells are rare, some operators will argue that a relief-well as a safety measure is no longer necessary because of technological advances in offshore drilling, including BOP’s. This approach has been presented with applications to drill in the high Arctic.

During the Macondo incident in the Gulf of Mexico, many advocated that relief-wells should be a required fail-safe to drilling in advance of any drilling operation since a relief-well is the only certain way to contain a blowout. While some suggest the spill in the Gulf has reinforced the need for the back-up wells, the industry is concerned that the U.S. spill could lead to a policy over-reaction and hinder future offshore development because such relief-wells will require additional time and money.

The ultimate solution to permanently capping a wild well is to inject cement from relief-wells drilled in from the side. Normally relief-wells start about a half mile from the original site and try to meet the original at a diagonal. They are drilled much the same as the primary well. Drills are equipped with directional sensors that do three-dimensional surveys to help the rig crew see where the drill bit is and what it is encountering, while metal detectors help guide it toward the metal in the original well. Once the drills intersect with the original well, typically just above or below where the problem occurred, cement is pumped in to seal it. A schematic of the relief wells drilling for the Macondo spill in the Gulf of Mexico is provided in Figure 12.

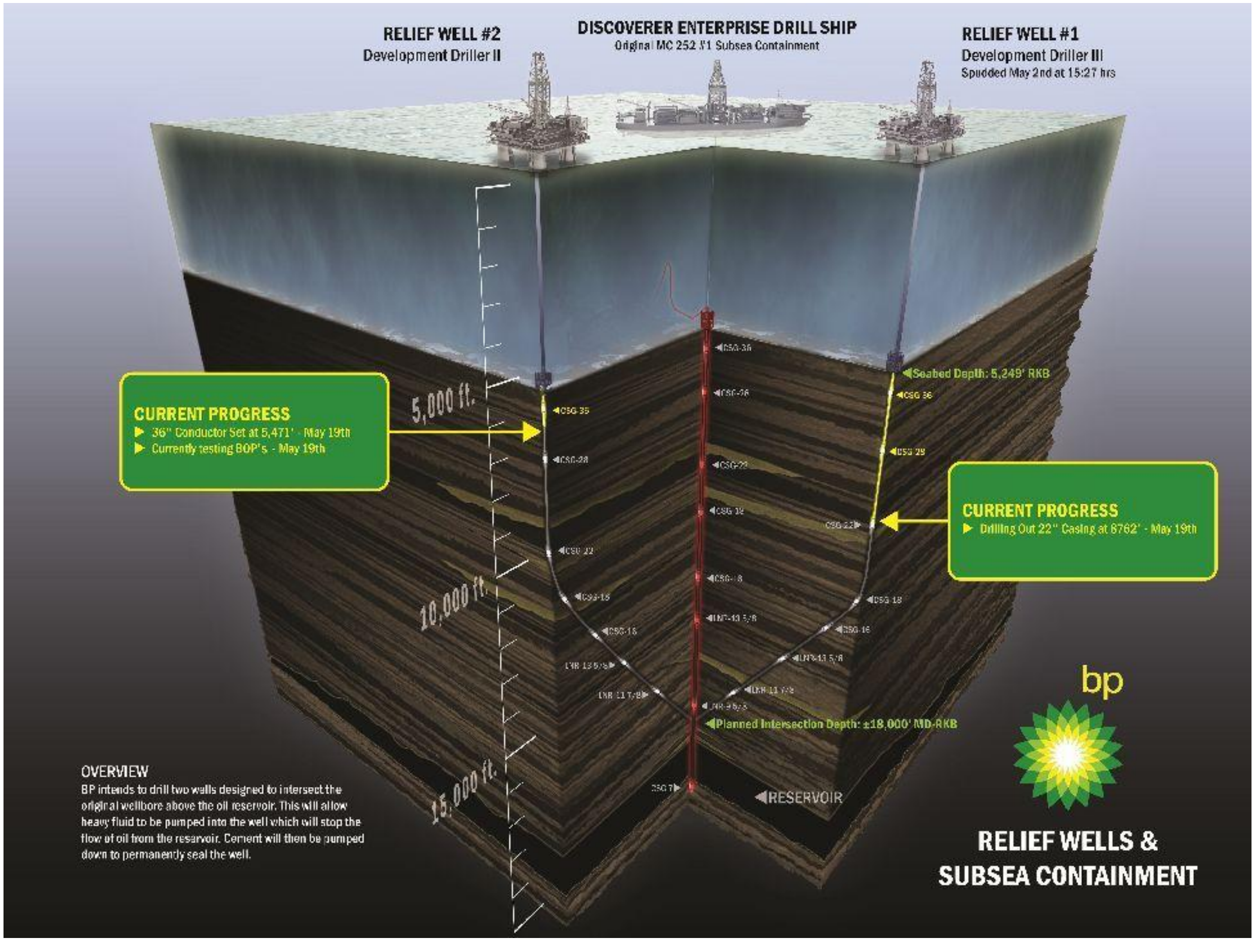


Figure 12 - Relief-wells for the Macondo Well Incident

Source: (Deepwater Horizon Response, 2010)

Drilling a relief-well is not that different from drilling a regular well except the target is much smaller. Relief-wells can also be fraught with challenges, especially working in deepwater on a well that has already had problem. Drill crews must be very careful and hopefully avoid another blowout while drilling a relief-well.

The Macondo spill has also presented the suggestion as to why the industry isn't regulated to drill relief-wells simultaneously with the primary well as a preemptive safety measure. That suggestion lacks proper reasoning; if you drill a relief-well before or while drilling the primary well, that well is subject to the same issues as the primary well. So effectively you may drill a number of proposed relief-wells with no enhanced success or reliability.

Simultaneous relief-well risks include:

- Increased risk of a blowout
- Increased risk due to simultaneous operations
- Increased risk of incidents, injuries and spills
- Questionable ability to use either well as a relief-well if a blowout occurs in either well
- Location of the relief-well and location of the relief-well drilling installation need to be chosen such that the blowout is not a hazard to the alternate installation

There are examples that demonstrate that there is no guarantee on the timing for drilling a relief-well, and that drilling a relief-well can be very dangerous. Prior to the Macondo spill, the world's worst well blowout and oil-spill was the Ixtoc I well in Mexico's Bay of Campeche in 1979. It was ultimately stopped with a relief-well after a containment dome, junk shot, and top kill all failed. Unfortunately, it took nearly ten months with multiple wells being drilled. Another example is the Montara oil well that blew out in the Timor Sea off Australia on August 21, 2009. It took ten weeks and five tries to drill the relief-well to hit its target over 2 600 metres below the sea floor. On the last attempt, there was another rig explosion. The oil flow was finally stopped on November 3rd, taking nearly three months to cap the well. Again, you must be extremely careful, because you don't want to experience another blowout if you hit petroleum or gas in another level. All relief-wells must be drilled with more caution than the primary well. It is very important that rig crews have the appropriate training and practice vigilance in monitoring and adhering to regulations. These are the best preventative measures.

2.2.3 Advancement in Relief-well Technology

Advancements in technology and application engineering over the past few decades have made the relief-well a more practical blowout control option. John W. Wright, a Blowout Advisor in Houston, Texas provides a good explanation of the design and execution of a relief-well operation…"More blowouts now warrant evaluation of a relief-well as a primary control option. In the past, relief-well developments in technology and strategy occurred only during unique blowout control operations. Now, however, a continuous process of improvement has evolved, aided by hydraulic kill models. As a result, strategic planning and new technology provide a more adaptive and efficient control option."

"The relief-well has traditionally been a last resort when other kill efforts fail. This has changed with increasing technology for horizontal, deep, offshore, hostile environment, or high pressure wells. Questions arose whether blowouts of some wells could be killed at all, especially with the possibility of underground blowouts. Fortunately, relief-well advancements paralleled this period of technology growth and now provide viable blowout control options. The operator of a blowing well will likely consider surface capping methods before snubbing or relief-well options. If a well clearly cannot be capped, the decision is simple - drill a relief-well. But if it is uncertain whether the well once capped can be killed, then additional options remain. These include (1) rig up a snubbing or coil tubing unit to run a kill string and perform a circulation kill, (2) drill a relief-well, or both. A planning team must quickly evaluate each option, associated safety risks, pollution, escalating severity, logistical obstacles, public concern, available resources, and other factors that might override preferred strategy. Complex, informed decisions must be made, especially when considering parallel surface and relief-well operations."

To make a decision, the operator must be aware of changes in technology, applications, planning technique, and demonstrated success. Starting a relief-well plan is not only cheap insurance should initial strategy fail, but a demonstrated means of efficiently killing blowouts.

The objective of a relief-well is to intercept, communicate and control a blowout if all else fails. A successful relief-well will overcome unknowns in the position of the blowout well. On occasion, the uncertainties are large enough that intercepting the blowout well with the relief-well would be impossible unless the blowout position can be accurately mapped relative to the relief-well. Due to better understanding of the earth's magnetic field and the ability to sample raw data from accelerometer and magnetometer arrays, quality control of surveys became easier. Relief-wells can be targeted more precisely with better information and more confidence. Distance and direction must be determined and ranging must be performed. Upon determining the relative position, relief-well trajectory can be modified in order to make the intercept. Log while drilling (LWD) and measurement while drilling (MWD) tools are used to investigate the unknowns in a systematic way (Wright & Flak, 1993).

2.2.4 Blowout Preventers

A BOP is a series of large heavy-duty valves used to control well pressure and contain wellbore fluid to prevent a blowout. The BOP is mounted atop the wellhead, which is cemented deep into the ground as drilling progresses. It may be composed of several failsafe mechanisms depending upon the specific configuration. In the series of stacked valves, the primary BOP is installed at the wellhead. In addition, a second BOP stack is designed to lock on top of the primary BOP. This provides additional capability to regain well-control in the event of a primary BOP stack failure.

Typically the upper two preventers are annular preventers designed to seal around almost any tubular and contain annulus well pressure, but cannot hold the weight of the drill string during disconnect. The middle two preventers are the shear and seal rams. In the event of an emergency or requirement for a rapid disconnect, one ram (Super Shear Ram) is designed to cut the tubular and the other ram (Shear Blind

Ram) to seal the wellbore. The lower four rams are generally pipe, casing or test rams. The pipe rams can be of varying sizes and will allow the full weight of the drill string to be suspended on them while sealing the annulus of the tubulars from well pressure (CAPP, 2010).

BOP's are designed with automatic failsafe mechanisms. A hydraulic actuator is the most common device used for this purpose. Hydraulic pressure is maintained between the BOP and drilling rig. In the event of the rig losing power, an emergency disconnect or a loss of communication between the well and the BOP, the BOP will automatically activate and shut down the well. All BOP's are incorporated with this system.

BOP's may also be designed with additional activation redundancies. A remote operated vehicle (ROV) system may be used to manually shut down the well. Acoustic systems, where a signal is sent from the rig to the BOP to activate and shut down the well, are now becoming more common.

Most operators use more than one of these devices, whereas some use all three. BOP's normally vary in size, styles and pressure rating. The design of the BOP and other well equipment must be approved by the C-NLOPB as part of the drilling application to the Board. Currently there are two rigs working predominantly in offshore Newfoundland and Labrador. These are the GSF Grand Banks and the Henry Goodrich. Both rigs use ROV intervention as the only backup system. The Stena Carron was in operation in offshore Newfoundland and Labrador during 2010, but has since left the province. During its operation, three BOP backup systems were utilized.

2.2.5 Deepwater Challenges for BOP's

BOP's have changed very little over the years. What have changed are the operating parameters and the manner in which BOP's are used in present drilling activities. Today, a subsea BOP can be required to operate in water depths greater than 3 000 metres at extremely high pressures, with internal wellbore temperatures greater than 200 degrees Celsius and external immersed temperatures close to freezing. The drilling challenges experienced by drilling contractors and oil companies alike are critical technical challenges that must be overcome if drilling is to move into deeper water environments.

Current deepwater BOP's can be required to remain subsea for extended periods of time ranging from 45 to 90 days for a single well, to more than a year in cases where drilling and completions on multiple wells are required. In all cases, however, when the BOP is called on to function in an emergency situation, it is the main mechanism protecting human life, the environment and capital equipment. Therefore it must function properly, without failure.

Today's drilling and production facilities are limited for space and handling capabilities, and therefore, require that BOP stacks be lighter weight and take up less space on the rig while providing the accustomed functionality. In addition, existing limited capacity rigs have the potential to be upgraded for use in deepwater with higher capability equipment, but the upgrade must be accomplished within limited height and weight parameters. With deck space and load capacity already at a premium, lighter weight BOP's can help offset distribution of alternative equipment such as subsea riser joints necessary for increased water depth capability.

BOP's today are also being used not only in drilling and work-over applications but also in completions and production environments. BOP's have traditionally evolved using conventional design methodology and today the envelope is rapidly changing, forcing some fundamental paradigm shifts. Emerging technologies give way to new manufacturing techniques and innovation of design and operation. Sealing technology has improved radically with new materials and compounds being used to formulate sealing elements able to withstand extreme temperatures and hostile fluid environments (Whitby, 2007).

2.3 Safety Culture

The safety culture of an organization describes the manner in which safety is managed within a workplace. It is a reference to the attitudes, beliefs, perceptions and values of employees with respect to safety. An employee's pattern of behavior and demonstrated level of proficiency relate back to the safety culture established within an organization (Mearns, Flin, & Whitaker, 2000). The safety culture of an organization highly influences the level of risk accepted during an operation, as well as the level of communication and trust between employees (Offshore Helicopter Safety Inquiry, 2010). The culture that is established in an organization directly influences the accepted behaviors of employees and the resulting level of risk. In short, safety culture defines the atmosphere in which an industry will operate and the accepted levels of risk in day to day and emergency operations.

To understand safety culture one must consider the influence of national, professional and organizational cultures on safety decisions. National culture refers to accepted norms, beliefs and attitudes of a nation as a whole, which varies tremendously throughout the world. Professional culture refers to standards, beliefs and norms accepted within a profession. For example, engineers throughout Canada make a vow of due-diligence to always uphold high levels of work to maintain faith in the profession and protect the public's best interest. Professional culture essentially refers to the pride of a profession and the standards to which practitioners will hold themselves to. Finally, the organizational culture is the encompassing component of national and professional culture. The organizational culture has the greatest leverage in creating an effective safety culture (Offshore Helicopter Safety Inquiry, 2010).

The maturity of a safety culture can be classified into five distinct stages. These are:

Pathological: Safety is of little concern. Primary focus is avoiding being caught for unsafe behaviors.

Reactive: Organizations primary motive is to fix accidents and incidents once they occur.

Calculative: Systems are in place to manage hazards. The systems are followed, but employees do not view them as important or critical to their operations.

Proactive: Systems are in place to manage hazards and employees believe them to be critical to their operation. A belief in safe operations is accepted as genuine.

Generative: Safety behavior is fully integrated into all components of an operation.

Source: Modified from (Offshore Helicopter Safety Inquiry, 2010) with original data from (Hudson, 2001).

The goal of an operation should be to achieve a generative safety culture within their operation. In doing so, operations will be as safe as reasonably possible in all areas. To develop a safety culture one must incorporate a reasonable reporting scheme, a fair system and room for flexibility (Offshore Helicopter Safety Inquiry, 2010). The key to creating a safe culture within an organization is creating an effective environment where risk can be well managed. This is achieved through Safety Management Systems (SMS). The key elements of an effective SMS are shown in Figure 13.

The majority of the information presented in this section has been derived from a report released for the Offshore Helicopter Safety Inquiry, released in May 2010. The report is titled "Overview of the best practice in Organizational & Safety Culture". The report is quite extensive in developing a theoretical basis for understanding safety culture. For further information concerning this topic, please refer to this report.

Figure 13 - Key Elements of a Safety Management System

Source: (Offshore Helicopter Safety Inquiry, 2010)

3.0 Canada-wide Regulatory Regimes

3.1 Canadian Environmental Assessment Agency

The Canadian Environmental Assessment Agency (CEAA) is the federal agency responsible for environmental assessments throughout Canada. The agency is directly accountable to the federal Minster of Environment. The agency provides high-quality environmental assessments to help contribute to informed decision making and support sustainable development (CEAA, 2010).

The CEAA's goal is to better protect the environment affected by projects of high economic value. In supporting and coordinating environmental assessments, the agency looks to reduce or eliminate the detrimental effects of a proposed project on the environment. The agency looks to integrate Canada's environmental goals with economic, social and cultural values. This is achieved through various measures, including administering the objectives of the *Canadian Environmental Assessment Act*. Additional roles of the agency include encouraging public participation in environmental assessments. The CEAA undertakes research and development initiatives to advance the science of environmental assessments. They also provide guidance and training to organizations to promote high-quality risk assessments. Administrative and advisory support is provided by the agency for all levels of assessments, including review panels, mediations, comprehensive studies and class screenings. Finally, the agency looks to promote the use of strategic environmental assessments as a valuable tool in sustainable decision making (CEAA, 2010).

The CEAA was established in 1994 in preparation for the enforcement of the *Canadian Environmental Assessment Act*, which came into effect on January 19, 1995. The Act ensures that projects are reviewed by the federal agency prior to approval to ensure minimal negative environmental effects. As with the goals of the agency, the Act ensures sustainable development and encourages public participation in the environmental assessment process. The Act looks to coordinate efforts between the Federal and Provincial Governments, as well as between the Governments and aboriginal peoples. The main goal is to ensure all development on Canadian lands does not significantly affect the environment (CEAA, 2010).

The scale of a project and the degree of environmental sensitivity dictate the form of environmental assessment required. There are four classes of assessments: screenings and class screenings, comprehensive studies, mediation and assessments by review panels. Screenings require an operator to document the environmental effects of a proposed project and determine ways to mitigate or eliminate the associated risk. Large-scale and environmentally sensitive projects require a comprehensive study. This is a more intensive assessment requiring mandatory opportunities for public participation. In the event of issues between parties, a mediation process may be required. In these cases, an impartial mediator is appointed by the Minster of the Environment to help in resolving issues. The final form of assessment is a panel review, which is required when the environmental effects of a project are uncertain, may be significant or warrant public concern. The Minister of the Environment appoints the review panel. The panel will listen to all points of view throughout the decision process (CEAA, 2010).

3.2 Transport Canada

Transport Canada is a federal department under the broader scope of the Transport, Infrastructure and Communities Portfolio. The department is responsible for transportation policies and programs throughout Canada. It ensures all modes of transportation, including air, marine, road and rail, are safe, secure, efficient and environmentally responsible (Transport Canada, 2010). The agency is directly accountable to the federal Minster of Transport, Infrastructure and Communities.

Transport Canada promotes safe and efficient transportation in Canada's marine environment, including offshore Newfoundland and Labrador. Their role in marine transportation includes promoting safe, secure and sustainable marine practices, overseeing marine infrastructure, regulating safe transportation of dangerous goods and helping protect the marine environment (Transport Canada, 2010).

Compliance and enforcement of safe practices during marine transportation is established under the *Canada Shipping Act* (CSA 2001). This Act is the primary legislation governing marine transportation, pollution and safety in Canada. The Act, written to bring legislation up-to-date with modern trends, has been enforced since July 1, 2007. One of the key objectives of the act is to establish an effective inspection and enforcement program to maintain safe and responsible marine practices. The National Compliance, Enforcement and Appeals Section of Transport Canada ensures National consistency of the Act's enforcement (Transport Canada, 2010).

Significant components of the *Canada Shipping Act* include Ship-source pollution, pollution regulations, pollution prevention regulations for ships with dangerous chemicals, ballast water control and management regulations, environmental response regulations, and enforcement of the Act provisions (Bird, 2007).

Enforcement of provisions of the *Canada Shipping Act* in relation to pollution and wildlife protection is a joint effort between Transport Canada and Environment Canada. This was established as part of a Memorandum of Understanding (MOU) in August 2006. Transport Canada is primarily responsible for ship inspections of Canadian and foreign vessels under CSA 2001 as well as various international conventions, whereas Environment Canada is responsible for inspections related to the disposal of waste at sea. Both organizations are responsible for investigating ship-source oil pollution at sea (Bird, 2007).

The *Canada Shipping Act* only applies to Canadian Flagged Vessels. To establish control over foreign flagged vessels in the Newfoundland and Labrador offshore, a MOU has been established between the C-NLOPB and Transport Canada. This MOU requires foreign flagged drilling operations to sign a *letter of compliance* prior to operating in Canadian waters.

Transport Canada has a significant role in relation to oil-spill prevention and response. This is clearly outlined in the Marine Oil-spill Preparedness and Response Regime Report to Parliament in 2006, in which numerous components of the current regime are mandated in the *Canada Shipping Act*.

3.3 National Energy Board

The National Energy Board (NEB) is an independent federal agency responsible for the regulation of international and interprovincial aspects of the oil, gas and electrical utilities industries. The purpose of the NEB is to regulate pipeline, energy developments and trade in the best interest of the Canadian public. The agency is directly accountable to the federal Minster of Natural Resources (NEB, 2010).

The NEB has various responsibilities in the natural resources sectors. Their governing responsibilities include the construction and operation of pipelines and power lines, traffic, tolls and tariffs, the export and import of energy, frontier oil and gas, the Northern Pipeline Agency, energy studies and advisory functions (NEB, 2010).

In relation to offshore oil and gas, the NEB has full regulatory responsibilities over all frontier land not regulated under joint federal/provincial accords. Various regulatory responsibilities are covered by the *Canada Oil and Gas Operations Act*, the *Canada Petroleum Resources Act* and the *Northern Pipeline Act*. Before a project can begin in an area under the NEB's jurisdiction, authorization from the NEB is required. This is a similar process to the Operations Authorization required by the C-NLOPB for offshore operations in the Newfoundland and Labrador offshore. Technical knowledge is exchanged between the NEB and the other federal/provincial agencies, including the C-NLOPB, C-NSOPB, Indian and Northern Affairs Canada and Natural Resources Canada (NEB, 2010).

As of December 31, 2009, new drilling and production regulations under the *Canadian Oil and Gas Operations Act* and the *Accord Acts* are now enforced by all offshore governing bodies, including the NEB and C-NLOPB. These new regulations replaced the old rules, and in doing so bring the regulations up-to-date with current technologies and approaches in offshore operations. The new measures help to ensure safety coincides with modernization.

3.4 The Canadian Coast Guard

The Canadian Coast Guard (CCG) is a special operating service of the Department of Fisheries and Oceans Canada (DFO). The CCG helps DFO meet its responsibilities in providing safe and accessible waterways throughout Canada. The CCG owns and operates the Federal Government's civilian fleet of vessels. These vessels provide a variety of services to maintain safety, accessibility, sustainability and development in Canadian waters. The CCG helps the Canadian Government to meet expectations regarding safety, security, healthy and productive waterways and coastlines (CCG, 2010).

The mandate of the CCG is stated in the *Oceans Act* and the *Canada Shipping Act*. The *Oceans Act* gives the federal Minister of Fisheries and Oceans responsibilities concerning navigational aids, marine communication and traffic management, ice-breaking and ice management, channel maintenance, search and rescue, pollution response and support for other Government agencies. The *Canada Shipping Act* gives the federal Minister responsibilities concerning navigation, search and rescue, pollution response and vessel traffic services (CCG, 2010).

The CCG provides numerous programs and services to mariners and vessels. These programs include aids to navigation, waterways management, ice-breaking, marine communications and traffic services, search and rescue and environmental response. These services help the CCG meet its mandate and highly relate to safety and spill prevention in Canadian waters.

The CCG's aid to navigation program provides a variety of conventional and electronic tools to aid navigation in Canadian waters. This includes a variety of floating, fixed and electronic navigation aids, national standards for aids to navigation, access to safety information and monitoring aid services. These aids help vessels move safely and quickly, protect the marine environment, maintain marine safety and progress marine development (CCG, 2010).

The CCG's waterway management program is designed to help ensure safe navigation, protect the marine environment and assist marine trade and commerce. This program is mainly concerned with the upkeep of marine passages such as the St. Lawrence waterway. It looks to ensure safe and environmentally responsible design, proper maintenance, provide channel safety information and represent the interest of commercial navigation (CCG, 2010).

The CCG is responsible for ice-breaking operations throughout Canada. The service helps marine traffic move safely and quickly through ice-covered waters. Specific services include ice information and ice routing advice, freeing trapped ships, vessel escorts, maintaining open ice tracks and monitoring ice conditions. In the winter season, the CCG operates 17 ice-breaking vessels along Canada's east coast from Newfoundland to Montreal (CCG, 2010).

Marine Communication and Traffic Services (MCTS) are provided by the CCG through various MCTS centres. These centres provide various services to the marine community, including detecting distress signals and sending help, screening unsafe vessels from entry into Canadian waters, broadcasting safety information, regulating vessel traffic, coordinating ship communication and managing marine information systems. The services are provided 24 hours a day, year round, through 22 centres across Canada (CCG, 2010). The CCG is also highly involved in search and rescue efforts and environmental response.

Review of Offshore Oil-spill Prevention and Remediation Requirements and Practices in Newfoundland and Labrador

December 2010

Appendix V

Background on the Regulatory Regime for Subsea Well-control and Oil-spill Readiness and Response

CANADA-NEWFOUNDLAND and LABRADOR OFFSHORE PETROLEUM BOARD

CANADA-TERRE-NEUVE et LABRADOR L'OFFICE DES HYDROCARBURES EXTRACÔTIERS

Backgrounder On The Regulatory Regime For Subsea Well Control And Oil Spill Readiness And Response

The C-NLOPB

The Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB, or The Board) was established in 1985 under the Atlantic Accord to regulate offshore oil and gas activity on behalf of the Governments of Canada and Newfoundland and Labrador. It is a seven person Board. Three members are appointed by the Government of Canada and three are appointed by the Government of Newfoundland and Labrador. The Chair and CEO is appointed jointly by both governments. Currently there are 69 staff with approximately 600 years of combined experience in offshore oil and gas.

The Board's mandate is to interpret and apply the provisions of the Atlantic Accord Implementations Act and regulations to the Newfoundland and Labrador offshore industry. Its mandate encompasses four key areas - worker safety, environmental protection, resource management, and industrial benefits. The Board states in its mission statement that worker safety and environmental protection will be paramount in all Board decisions.

In addition to the legislation, the Board provides guidance to industry, which is developed on the basis of experience and expertise here in Newfoundland and Labrador and best practices from around the world. There is a rigorous and exhaustive regulatory process, which focuses first, and foremost, on worker safety, and protection of the environment.

Offshore regulators in some countries have a role in fiscal matters, but the Board has no such role beyond the provision of required data and information to government. The Board has no part in the establishment or administration of royalties or taxes for any offshore activity. It does not promote the industry. That is the role of governments. The Board's role is one of independent regulatory oversight of Operator activity. The term 'Operator' refers to companies who hold operating permits issued by the Board.

The Atlantic Accord legislation defines a Chief Safety Officer with broad powers and responsibilities for worker safety, as well as a Chief Conservation Officer with powers over resource management. The legislation stipulates that an order made by the Chief Safety Officer cannot be overruled by the Board and it prevails over a decision of the Chief Conservation Officer. The Atlantic Accord legislation therefore already accomplishes what the United States is proposing to do now with respect to separating some of the responsibilities of the Minerals Management Service. In short, the legislation provides that in matters of safety versus resource management and production issues, safety is paramount.

The Newfoundland and Labrador Offshore Industry

Drilling for oil and gas in our offshore area began over forty years ago in 1966 and there has been considerable accumulation of experience and expertise over the past four decades. Since that time, 355 wells have been drilled including: 144 exploration wells, 50 delineation wells and 161 development wells. Of the total number of wells drilled in our offshore, 15 have been in deep water, which means depths of 500 metres or more.

Production of oil from our offshore area started in 1997. As of the end of March 2010, 1.1 billion barrels of oil have been produced from three projects: Hibernia, Terra Nova and White Rose. In 2009-10, there were 27 reportable injuries and just over 4.2 million person hours worked. This gives the industry a Reportable Injury Frequency Rate of 1.28 per 200,000 person hours worked. Apart from the 1000 barrel spill that occurred in 2004 in the Terra Nova field, 101 barrels of crude have been spilled in the Newfoundland offshore area. That means there has been 1 barrel spilled for every 1 million barrels produced. There have been no blowouts in our offshore area. Obviously the Board would prefer to have no injuries or spills, but the record for the Newfoundland and Labrador offshore area is quite respectable.

Currently, there is one exploration drilling program taking place in the Newfoundland and Labrador offshore area. Chevron Canada Limited is drilling the Lona O-55 exploration well on behalf of itself and its co-venture partners ExxonMobil Canada Limited, Imperial Oil Resources Ventures Limited and Shell Canada Limited. The well is located 427 kilometres northeast of St. John's at a water depth of 2586 metres.

Offshore Safety and Environmental Protection Regime

The Gulf of Mexico incident is a reminder that accidents can happen. Regulations and regulators are designed to require that the risk of an offshore incident occurring is reduced to a level that is "as low as reasonably practicable". The optimization of safety offshore was stated quite well in the 1985 Report of the Royal Commission into the *Ocean Ranger* Marine Disaster when it said: "High standards of safety in the workplace are achieved when well-designed equipment is operated properly by well-managed and trained persons. Occupational safety is maintained by keeping these factors in a state of positive balance, in what is normally a highly dynamic situation." However, equipment failure and human error does occur, which leads to tragedies like the Deepwater Horizon incident. This is a reality that safety regulators deal with as part of their responsibilities. It is precisely for this reason that safety regulators focus on ways to improve safety and prevent accidents from occurring.

Environmental protection in the offshore area encompasses two concepts – protection **of** the environment and protection **from** the environment. Protection of the environment recognizes that Operator activities may have environmental impact and it is the role of the regulatory body to oversee the mitigation of these activities when they occur. Protection from the environment recognizes that Operators work in a harsh environment where such things as icebergs and storms present substantial challenges and risks to installations and the people who work on the installations. Environmental protection is governed by two pieces of legislation – the *Atlantic Accord Implementation Act* and the *Canadian Environmental Assessment Act.*

The Regulatory Approval Process for Drilling Programs

The Board's oversight of an offshore drilling program commences at the early planning stage, typically 18 months or more in advance of any proposed program. A key step in the oversight model is to ensure that the various statutory and regulatory requirements are communicated effectively to prospective Operators so that these matters can be taken into account throughout the contracting and procurement phases. This is particularly important to the acquisition of the drilling installation, supply vessels, helicopters, and numerous other long-lead aspects that affect the safety of the program.

Before drilling programs even are contemplated, before the relevant licences are issued in a potential area of exploration, the Board undertakes a Strategic Environmental Assessment, or SEA, of potential operations in that area. This involves a public consultation process. This initiative is over and above the requirements of both the Accord Legislation and the current federal environmental assessment legislation. The SEA for the Orphan Basin area was undertaken in 2003 and included solicitation of public comments on both the scoping document for the SEA, at the outset of the process, and on a draft of the final report. The final report was posted on the Board's Web site in November 2003 and still is available there today. The SEA, while necessarily more of an overview nature than subsequent project-specific assessments, included consideration of potential blowout risk and fate. These assessments typically identify any mitigative measures necessary in respect of the environmental risks identified. These measures are included as conditions to the Board's Operations Authorization for greater certainty with respect to the legal obligation of the Operator to abide by these requirements

Particular oversight is provided in respect of drilling and well control matters. This involves a review of the Operator's well planning and technical capabilities in respect of well and casing design, marine riser analysis, well control matters, kick prevention and detection, mitigation of hydrate hazards, establishment of severe weather operating limits, a review of emergency disconnect requirements and an assessment of the relief well drilling arrangements. Emphasis is also placed on ensuring that all personnel have the requisite certificated training in well control and blowout prevention. Marine issues associated with the DP system are also assessed and a review is conducted to ensure suitable redundancy of the BOP control systems in the event of any situation that could result in a disconnect from the well.

Oversight of these matters is achieved in a systematic manner through the Board's Safety Assessment System. This system includes a comprehensive checklist addressing all key regulatory elements and requirements. The safety assessment system includes a review of the Operator's safety management system and confirmation that the Operator has identified the hazards and the measures to be put in place to reduce the risk from these hazards to a level that is as low as reasonably practical.

The regulatory approval process is a two tiered process that requires firstly, authorization of the overall drilling program in the form of an Operations Authorization, and secondly, a well approval, in the form of an Approval to Drill a Well for each well to be drilled as part of the drilling program.

Tier 1 – Operations Authorization (OA)

Before an Operations Authorization can be issued, a number of statutory obligations must be met. The applicant must have completed the environmental assessment process required by both the Canadian Environmental Assessment Act as well as the Atlantic Accord Act.

The project specific environmental assessment (EA) process includes preparation of a detailed technical report describing potential effects of the environment on the proposed project (e.g., weather, wave and ice conditions) and the potential effects of the project on the environment. The latter includes effects due to accidental events. The project proponent is expected to consult with potentially affected parties (in particular, fishing interests). All substantive documents associated with the EA are publically available in near real time on the Board's website, and are reviewed by technical experts on staff at the Board and at federal and provincial departments.

In addition, the operator must have obtained a Certificate of Fitness from an independent third party Certifying Authority. The Certifying Authority is an agency that reviews installations to ensure they are fit for purpose, function as intended and meet the requirements of the regulations. There are only a few of these in the world and under the legislation, only a few of them are allowed to operate in the Newfoundland and Labrador offshore. As well, the operator must obtain a Letter of Compliance from Transport Canada for the drilling installation; and, they must file a Safety Plan, an Environmental Protection Plan and a Contingency Plan that includes an Oil Spill Response Plan. In addition, they must submit documentation respecting financial responsibility, obtain approval of the Canada-Newfoundland and Labrador Benefits Plan, and finally, they must provide a Declaration of Fitness, in the form and manner prescribed by the Board attesting that the equipment and facilities to be used during their program are fit for purpose, the operating procedures relating to them are appropriate, the personnel employed are qualified and competent and the installation meets all necessary Canadian standards. Only after all this documentation has been presented to and approved by the Board can an Operator proceed with an application.

The Certificate of Fitness is required by both the Act and by Regulations. This must be issued by one of the Certifying Authorities listed in the Certificate of Fitness Regulations before the installation can be used to conduct any activity in the offshore area. Although it is the ultimate responsibility of the Operator to ensure that the program, including the facilities, comply with the regulations and to ensure that the program can be conducted safely without polluting the environment, the purpose of this additional certification is to provide an independent third party assurance and verification that the installation is fit for purpose, functions as intended and meets the requirements of the regulations. Of particular interest is the fact that the certification explicitly includes the BOP stack and other related well control equipment.

The scope of work to be executed by the Certifying Authority explicitly requires the approval of the Board's Chief Safety Officer. The scope of this work addresses the maintenance, inspecting and testing programs of the facilities and equipment with a particular focus on safety critical elements. During this process, surveys are conducted prior to the issuance of the certificate and on an ongoing basis as part of the need to periodically verify the continued integrity of the installation. Once such survey is currently in progress at Marystown, Newfoundland in connection with the Henry Goodrich rig. In addition, all modifications or repairs to the installation that affects its strength, stability, integrity, operability, safety or regulatory compliance needs to be reviewed and accepted by the Certifying Authority to ensure the continued validity of the certificate. It is a condition of the Operations Authorization that all required certificates remain valid in order to maintain the validity of the Operations Authorization.

An additional marine safety measure for our offshore area arises from a Memoranda of Understanding between the C-NLOPB and Transport Canada. This MOU requires the issuance of a Letter of Compliance verifying compliance to the MODU code for any foreign flagged drilling installations. While the Canada Shipping Act only requires this for Canadian flagged vessels, the C-NLOPB insists that this be in place for any foreign flagged vessels as well, in addition to the Certificate of Fitness, as an added measure for marine safety.

Oversight of these matters is achieved in a systematic manner through the Board's Safety Assessment System. This system includes a comprehensive checklist addressing all key regulatory elements and requirements. The safety assessment system includes a review of the Operator's safety management system and confirmation that the Operator has identified the hazards and the measures to be put in place to reduce the risk from these hazards to a level that is as low as reasonably practical.

Tier 2 – Approval to Drill a Well (ADW)

The second tier of the approval process involves the requirement to obtain an Approval to Drill a Well or ADW. This approval is required for each and every well drilled. The ADW must provide detailed information on the drilling program and well design, including the BOP equipment and the casing and cementing program as well as the geologic prognosis and identification of structures and targets.

The application for this approval must identify and discuss drilling related hazards including matters pertaining to well control and blowout prevention. The depth and nature of formations where problems such as high pressure and other hazards are anticipated must be identified. The program must include a description of the casing and cementing program as well as details of the casing design, the proposed casing pressure testing program, the drilling fluid program, the directional drilling and survey plans and information respecting pressure testing and function testing of the well control equipment. This application is reviewed by a multi-disciplinary team within the C-NLOPB consisting of engineers, technicians, geologists, geophysicists and environmental scientists prior to the issuance of the ADW.

The expectations respecting the various cement plugs that need to be set and pressure tested at the end of the well are also described in the Board's guidelines. These requirements reflect the practices and procedures for plugging and abandoning wells that have been successfully used in the Newfoundland and Labrador offshore area since the Board's inception.

The drilling and production guidelines speak to all critical matters in relation to well barriers, blowout prevention and well control including BOP stacks, casing and cementing matters as well as detailed requirements and expectations pertaining to the plugging and abandonment of wells. These guidelines reflect high standards and modern thinking with respect to drilling, cementing and well control matters. The guidelines can be updated as required to incorporate lessons learned from audits and inspections as well as technological advances and improvements to best practices.

Goal Oriented Regulations

The Operations Authorization process and the ADW process has been recently updated to reflect the requirements of the modernized set of drilling and production regulations that came into effect on December 31, 2009. The C-NLOPB, together with the CNSOPB has supplemented these goal-oriented regulations with comprehensive guidelines in four key areas:

1) Drilling and Production Guidelines
2) Safety Plan Guidelines
3) Environmental Protection Guidelines
4) Data Acquisition and Reporting Guidelines

The drilling and production guidelines speak to all critical matters in relation to well barriers, blowout prevention and well control including BOP stacks, casing and cementing matters as well as detailed requirements and expectations pertaining to the plugging and abandonment of wells. These guidelines reflect high standards and modern thinking with respect to drilling, cementing and well control matters. The guidelines can be updated as required to incorporate lessons learned from audits and inspections as well as technological advances and improvements to best practices. An excellent description of goal-oriented regulations can be found on page 2337 in the Regulatory Impact Assessment Statement available at this link: http://www.gazette.gc.ca/rp-pr/p2/2009/2009-12-09/pdf/g2-14325.pdf

Chevron Canada's Lona O-55 Well Program

Chevron Canada Limited was issued an ADW, or Approval to Drill a Well, on April 23rd after having met all the regulatory requirements under the Drilling and Production Regulations and associated Board guidelines. Chevron's Safety Plan identifies hazards, including a blowout, and describes how these hazards will be managed. Their Safety Plan describes the use of appropriate equipment, proper procedures and competent personnel to undertake safe drilling operations. Chevron is using the *Stena Carron* drill ship, which is a state-of-the-art, 6th generation harsh environment drillship. It is a dynamically positioned (DP) vessel, which means that it uses thrusters, instead of anchors, to keep it in position. The BOP can be activated from the drill floor using one of two buttons. This redundancy helps ensure that the well can be shut in by the drilling crew. The vessel also has three back-up systems capable of activating the BOP and shutting in the well should the need arise to do so – it has the acoustic system; ROV intervention capability, and an automode function (AMF), which automatically activates the BOP and shuts in the well when the signal is lost.

Prior to starting operations on the Lona O-55 Exploration Well, the *Stena Carron* was contracted out to ConocoPhillips in the Laurentian Basin off the Southern Coast of Newfoundland and Labrador. The ConocoPhillips East Wolverine G-37 well was also a deepwater exploration well, in 1890 m of water, which was successully drilled to Total Depth (TD), logged and then plugged and abandoned.

The Lona O-55 Exploration Well was spudded on May 10, 2010. The conductor and surface casings have been successfully drilled and cemented as per the approved drilling program. As well, the Blowout Preventer (BOP) was fully pressure and function tested, including back-up activation systems, and was run on riser and installed on the wellhead on May 19, 2010. In this respect, Chevron has provided the Board with copies of the field reports of the noted BOP testing. Chevron is currently drilling the hole section for the next casing point and continues to conduct drilling operations as per the approved ADW. At this point in time, drilling operations are proceeding fairly closely with the program schedule, which means the well should be completed in early September if the scheduled is maintained.

Increased Oversight Measures

In light of the situation unfolding in the Gulf of Mexico and heightened public concern over drilling operations currently underway in the Newfoundland and Labrador offshore area, the Board has taken the following measures for overseeing well operations at Chevron's Lona O-55 well. These measures are in addition to requirements contained in the Drilling and Production regulations and associated guidelines.

A team has been established within the Board to provide regulatory oversight of Chevron's operations. This team is comprised of the Chief Safety Officer, the Chief Conservation Officer, members of the Board's Management Team and selected senior staff with extensive experience in the regulatory oversight of drilling programs. Chevron is expected to ensure the timely posting of daily reports (7 days a week) so that up-to-date information is always available to this team.

Chevron is required to meet with the Board's oversight team every two weeks to review everything associated with the well. The Board's Chief Safety Officer will chair these meetings.

Chevron is required to provide the Board's Well Operations Engineer with copies of the field reports prepared in respect of the following: testing of the blowout preventer (BOP) stack; function test of the acoustic control system; function test of the Remotely Operated Vehicle (ROV) intervention capability and function test of the automode function (AMF) system, together with an assessment of the readiness of the ROV system in terms of equipment, procedures and spare parts.

Chevron is expected to monitor developments at the Deepwater Horizon incident and provide periodic assessments on the impact of any lessons learned from that situation to operations at Lona O-55, in particular any lessons learned with respect to well operations, BOP equipment or spill response readiness.

The frequency of audits and inspections onboard the *Stena Carron* will be approximately every three to four weeks. Normally, audits and inspections are conducted on offshore operators every 3-4 months.

Prior to penetrating any of the targets, Chevron must hold an operations time-out to review and verify, to the satisfaction of the Chief Safety Officer and the Chief Conservation Officer, that all appropriate equipment, systems and procedures are in place to allow operations to proceed safely and without polluting the environment.

Prior to penetrating any of the targets, Chevron should assure itself and the Board that all personnel and equipment for spill response identified in its oil spill contingency plan are available for rapid deployment.

Chevron must also make arrangements for a representative of the Board to be onboard the *Stena Carron* to observe the cementing operations of the last casing string set prior to entering any target zones. The observer will also be present to witness the BOP testing, well control drills, and results of the pressure test of the cementing job.

In the case of the BOP testing, a representative of the Certifying Authority will also be present.

In due course, Chevron must provide, for review and assessment by the Board's oversight team, a copy of the proposed well termination program to be issued to field personnel for implementation.

Chevron must also make the necessary arrangements for a representative of the Board to be onboard the *Stena Carron* to observe the well termination program.

Review of Offshore Oil-spill Prevention and Remediation Requirements and Practices in Newfoundland and Labrador

December 2010

Appendix VI

Statement by Max Ruelokke P.Eng, Chair and CEO,

C-NLOPB (Made to the House of Commons Standing

Committee on Natural Resources on May 25, 2010)

CANADA-NEWFOUNDLAND and LABRADOR OFFSHORE PETROLEUM BOARD

CANADA-TERRE-NEUVE et LABRADOR L'OFFICE DES HYDROCARBURES EXTRACÔTIERS

STATEMENT BY MAX RUELOKKE P.ENG, CHAIR AND CEO

Made to the House of Commons Standing Committee on Natural Resources

May 25, 2010

Mr. Chairman and members of the Committee, I would like to begin my comments to you by expressing the heartfelt sympathy of all of us at the Canada-Newfoundland and Labrador Offshore Petroleum Board for the families and friends of those who were killed or injured in the April 20th explosion on the Deepwater Horizon. Our hearts and prayers go out to them and to the victims.

The Board was established in 1985 under the Atlantic Accord to regulate offshore oil and gas activity on behalf of the Governments of Canada and Newfoundland and Labrador. We have 69 staff with approximately 600 years of combined experience in offshore oil and gas. Our mandate encompasses four key areas - worker safety, environmental protection, resource management, and industrial benefits. The Board's mission statement confirms that worker safety and environmental protection will be paramount in all Board decisions. The Board has no part in the establishment or administration of royalties or taxes for any offshore activity. We do not promote the industry. That is the role of governments. Our role is one of regulatory oversight of Operator activity. The term 'Operator' refers to companies who hold operating permits issued by the Board.

The Atlantic Accord legislation defines a Chief Safety Officer with broad powers and responsibilities for worker safety, as well as a Chief Conservation Officer with powers over resource management. The legislation stipulates that an order made by the Chief Safety Officer cannot be overruled by the Board, and it prevails over a decision of the Chief Conservation Officer. The Atlantic Accord legislation therefore already accomplishes what the United States is proposing to do now with respect to separating some of the responsibilities of the Minerals Management Service. In short, our legislation provides that in matters of safety versus resource management and production, safety is paramount.

Drilling for oil and gas in the Newfoundland and Labrador Offshore Area began over forty years ago in 1966. Since that time, 355 wells have been drilled including 144 exploration wells. Fifteen wells have been in deep water, which is considered to be 500 metres or more. Production of oil from our offshore area started in 1997. As of the end of March 2010, 1.1 billion barrels of oil have been produced from three projects: Hibernia, Terra Nova and White Rose. Since the beginning of production, 1,100 barrels of crude have been spilled in our offshore area – 1 barrel per 1 million produced. There have been no blowouts in our offshore area. Obviously we would prefer to have no injuries or spills, but we believe that the record for our offshore area is quite respectable.

Currently, there is one exploration drilling program taking place in our offshore area. Chevron Canada Limited is drilling the Lona O-55 exploration well, 427 kilometres northeast of St. John's at a water depth of approximately 2600 metres. I will speak to this project in further detail shortly.

The Board's mandate is to interpret and apply the provisions of the *Atlantic Accord Implementation Act* and regulations to the Newfoundland and Labrador offshore industry. In addition to the legislation, the Board provides guidance to industry, which is developed on the basis of experience and expertise here and best practices from around the world.

The Gulf of Mexico incident is a reminder that accidents can happen. Regulations and regulators are designed to require that the risk of an offshore incident occurring is reduced to a level that is "as low as reasonably practicable". This is a reality that safety regulators deal with as part of our responsibilities. It is precisely for this reason that safety regulators focus on ways to improve safety and prevent accidents from occurring.

Before drilling programs even are contemplated, before the relevant licences are issued in a potential area of exploration, the Board undertakes a Strategic Environmental Assessment, or SEA, of potential operations in that area. This initiative is over and above the requirements of both the Accord Legislation and the current federal environmental assessment legislation. The SEA for the Orphan Basin area was undertaken in 2003 and included solicitation of public comments on both the scoping document for the SEA, at the outset of the process, and on a draft of the final report. The final report was posted on the Board's web site in November 2003 and still is available there today. The SEA, while necessarily more of an overview nature than subsequent project-specific assessments, included consideration of potential blowout risk and fate.

I would like to describe for you the regulatory approval process for drilling programs.

As part of the planning process for a drilling program, and before any authorization respecting the program is issued, an environmental assessment of the proposed program is conducted. The assessment is conducted under both the federal *Canadian Environmental Assessment Act* and the Accord legislation. In the case of the Orphan Basin drilling program, the assessment was concluded in July 2006, prior to authorization of Chevron's first well in the area, the deepwater exploration well Great Barasway F-66. The documentation associated with this assessment, like all such Board assessments, is publicly available and the principal documents still can be downloaded from the Board's web site.

The Board's oversight of an offshore drilling program commences at the early planning stage, typically 18 months or more in advance of any proposed program. The operational review and approval of drilling programs is a two tiered process that requires firstly, an Operations Authorization, and secondly, an Approval to Drill a Well for each well to be drilled as part of the drilling program.

Prior to receiving the Operations Authorization a number of statutory obligations must have been met. The applicant must have completed the environmental assessment process required by both the *Canadian Environmental Assessment Act* as well as the *Atlantic Accord Implementation Act*. The operator must have obtained a Certificate of Fitness from an independent third party Certifying Authority, a Letter of Compliance from Transport Canada for the drilling installation; and, they must file a Safety Plan, an Environmental Protection Plan and a Contingency Plan that includes an Oil Spill Response Plan. In addition, they must submit documentation respecting financial responsibility, and finally, they must provide a Declaration of Fitness, attesting that the equipment and facilities to be used during their program are fit for purpose, the operating procedures relating to them are appropriate, the personnel employed are qualified and competent, and the installation meets all necessary Canadian standards. Only after all of this documentation is presented to and approved by the Board, may an operator proceed with the application.

Drilling and well control are critical aspects of offshore operations and are addressed extensively in the regulatory framework. This involves a review of the Operator's well planning and technical capabilities in respect of well and casing design, well control matters, kick prevention and detection, establishment of severe weather operating limits, a review of emergency disconnect requirements and an assessment of the relief well drilling arrangements. Emphasis is also placed on ensuring that all personnel have the requisite training in well control and blowout prevention. A review is conducted to ensure suitable redundancy of the blowout prevention (BOP) control systems, in the event of any situation that could result in a disconnect from the well.

Oversight of these matters is achieved in a systematic manner through the Board's Safety Assessment System, which includes a review of the Operator's safety management system and confirmation that the Operator has identified the hazards and the measures to be put in place to reduce the risk from these hazards to a level that is as low as reasonably practicable.

Last but not least, the Board's safety and environment professionals review the emergency response plans for the project, in the event that an incident occurs despite the preventative measures in place. These plans include an oil spill response plan, which describes in detail the command structure the operator will put in place to respond to a spill event. It also describes the plan's relationship with other operators' and governments' plans and a description of spill response resources available at site, in eastern Newfoundland, nationally, and internationally. Locally available resources include large containment and recovery systems – boom-and-skimmer systems – with fluid pumping capacities of over 50,000 barrels per day each.

Detailed modeling of the potential fate of a spill at these locations, using 40 years of weather data, indicates that even if a large spill were to occur, it would be unlikely that oil would approach the Newfoundland and Labrador shoreline. Thus, scenes like we see on the coast of Louisiana would not occur here. The impacts of a spill occurring this far from the Canadian coastline nevertheless could be serious and would require immediate response, but it would be a situation substantially different from what we are seeing in the United States today.

The second tier of the approval process involves the requirement to obtain an Approval to Drill a Well or ADW for each and every well drilled. The ADW must provide detailed information on the drilling program and well design, including the BOP equipment and the casing and cementing program as well as the geologic prognosis. This application is reviewed by a multi-disciplinary team within the Board consisting of engineers, technicians, geologists, geophysicists and environmental scientists prior to the issuance of the ADW.

The drilling and production guidelines in place speak to all critical matters in relation to well barriers, blowout prevention and well control including BOP stacks, casing and cementing matters as well as detailed requirements and expectations pertaining to the termination of wells. These guidelines reflect high standards and modern thinking with respect to drilling, cementing and well control matters.

Mr. Chairman and committee members, Chevron Canada Limited has been issued an ADW for the Lona O-55 well after having met all the regulatory requirements under the Drilling and Production Regulations and associated Board guidelines. Chevron's Safety Plan identifies all hazards, including a blowout, and describes how these hazards will be managed. Their Safety Plan describes the use of appropriate equipment, proper procedures and competent personnel to undertake safe drilling operations. Chevron is using the *Stena Carron* drill ship, which is a state-of-the-art, 6th generation harsh environment drillship.

The BOP can be activated from the drill floor using either of two hydraulic control systems. This redundancy helps ensure that the well can be shut in by the drilling crew. The vessel also has three back-up systems capable of activating the BOP and shutting in the well should the need arise to do so – it has the acoustic system; ROV intervention capability, and an automode function (AMF), which automatically activates the BOP and shuts in the well when the signal is lost.

Prior to starting operations on the Lona O-55 exploration well, the *Stena Carron* was contracted out to ConocoPhillips in the Laurentian Basin off the Southern Coast of Newfoundland and Labrador. The ConocoPhillips East Wolverine G-37 well was also a deepwater exploration well, in 1,890 metres of water, which was successfully drilled to Total Depth (TD), logged and then terminated.

The Lona O-55 well was spudded on May 10, 2010. The Blowout Preventer (BOP) was fully pressure and function tested, including back-up activation systems, and was run in preparation for it to be run on riser and installed on the wellhead. Chevron continues to conduct drilling operations as per the approved ADW and the well should be completed in early September if the schedule is maintained.

Mr. Chairman and members of the committee, it is prudent practice for a regulator to conduct an internal review following an incident like the one in the Gulf of Mexico to determine if more can be done from an oversight perspective to address concerns about the risks of offshore drilling. In light of the situation unfolding in the Gulf of Mexico and heightened public concern over drilling operations currently underway in the

Newfoundland and Labrador Offshore Area, the Board has taken the following measures for overseeing well operations at Chevron's Lona O-55 well. These measures are in addition to requirements contained in the Drilling and Production regulations and associated guidelines.

A team has been established within the Board to provide regulatory oversight of Chevron's operations. This team is comprised of the Chief Safety Officer, the Chief Conservation Officer, members of the Board's Management Team and selected senior staff with extensive experience in the regulatory oversight of drilling programs. Chevron is expected to ensure the timely posting of daily reports (seven days a week) so that up-to-date information is always available to this team.

Chevron is required to meet with the Board's oversight team every two weeks to review everything associated with the well. The Board's Chief Safety Officer will chair these meetings.

Chevron is required to provide the Board's Well Operations Engineer with copies of the field reports prepared in respect of the following: testing of the blowout preventer (BOP) stack; function test of the acoustic control system; function test of the Remotely Operated Vehicle (ROV) intervention capability and function test of the automode function (AMF) system, together with an assessment of the readiness of the ROV system in terms of equipment, procedures and spare parts.

Chevron is expected to monitor developments at the Deepwater Horizon incident and provide periodic assessments on the impact of any lessons learned from that situation to operations at Lona O-55, in particular any lessons learned with respect to well operations, BOP equipment or spill response readiness.

The frequency of audits and inspections onboard the *Stena Carron* will be approximately every three to four weeks. Normally, audits and inspections are conducted on offshore operators every 3-4 months.

Prior to penetrating any of the targets, Chevron must hold an operations time-out to review and verify, to the satisfaction of the Chief Safety Officer and the Chief Conservation Officer, that all appropriate equipment, systems and procedures are in place to allow operations to proceed safely and without polluting the environment.

Prior to penetrating any of the targets, Chevron should assure itself and the Board that all personnel and equipment for spill response identified in its oil spill contingency plan are available for rapid deployment.

Chevron must also make arrangements for a representative of the Board to be onboard the *Stena Carron* to observe the cementing operations of the last casing string set prior to entering any target zones. The observer will also be present to witness the BOP testing, well control drills, and results of the pressure test of the cementing job.

In the case of the BOP testing, a representative of the Certifying Authority will also be present.

In due course, Chevron must provide, for review and assessment by the Board's oversight team, a copy of the proposed well termination program to be issued to field personnel for implementation.

Chevron must also make the necessary arrangements for a representative of the Board to be onboard the *Stena Carron* to observe the well termination program.

In closing, the Board is confident that it administers a robust safety and environmental protection regime. Operators here work in a harsh environment, which demands diligence on their part to reduce risks as low as reasonably practicable. It is our role as the regulator to oversee their program – a role to which all of us at the Board are dedicated.

Note: This statement was also presented to the Senate Standing Committee on Energy, Environment and Natural Resources on May 27, 2010.

Review of Offshore Oil-spill Prevention and Remediation Requirements and Practices in Newfoundland and Labrador

December 2010

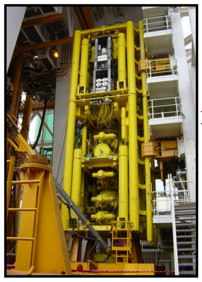
Appendix VII

Subsea Well-control for Drilling Operations and Oil-spill Readiness (Prepared by the C-NLOPB as a Technical Briefing for Media on June 2, 2010)

Subsea Well Control for Drilling Operations and Oil Spill Readiness

C-NLOPB Technical Briefing for Media – June 2, 2010

Drillers Cabin



BOP Stack

Containment Boom

Legislative Requirements

- Regulations
  - Drilling and Production Regulations
  - Certificate of Fitness
  - Oil and Gas Debris and Spills Liability
  - Petroleum Installations
- Guidance
  - Drilling and Production Guidelines
  - Drilling Programs
  - Safety Plans
  - Incident Reporting and Investigation
  - Environmental Protection Plan
  - Physical Environmental Programs
  - Data Acquisition and Reporting
  - Financial Responsibility Requirements

Environmental Assessment

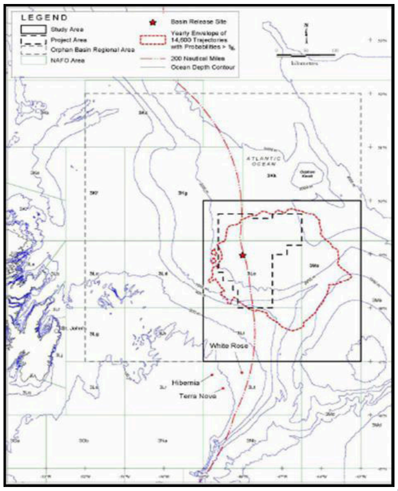
- Strategic Environmental Assessment
  - Conducted by C-NLOPB prior to issuing exploration licences
  - Reviewed by federal and NL agencies, including fisheries, environment
  - Draft report published for public comment
  - Report available on C-NLOPB Web site
  - Includes overview of blowout risk and consequences

Environmental Assessment

- Project Specific Environmental Assessment
  - Conducted in accordance with *Canadian Environmental Assessment Act*
  - Documents published on C-NLOPB Web site in near-real time
  - Assessment documents reviewed by staff of C-NLOPB, environment and fisheries agencies of federal and NL governments
  - Includes potential effects due to accidental events, including blowouts

Trajectory Model Results: Orphan Basin

- From original assessment using typical basin release point
- Model simulate one release per day for 40 years using actual wind data
- No trajectories reached shore
- Figure indicates area with > 1% probability of having oil present over this period



Authorization Requirements

- Operations Authorization (OA)
  - Safety Plan
  - Environmental Assessment
  - Environmental Protection Plan
  - Contingency Plans
    - Offshore and Onshore Emergency Response Plans
    - Oil Spill Response Plan
    - Ice Management
    - Relief Wells
  - Certificate of Fitness
  - Operator's Declaration of Fitness
  - Letter of Compliance
  - Financial Responsibility
  - C-NL Benefits Plan

Approval Requirements

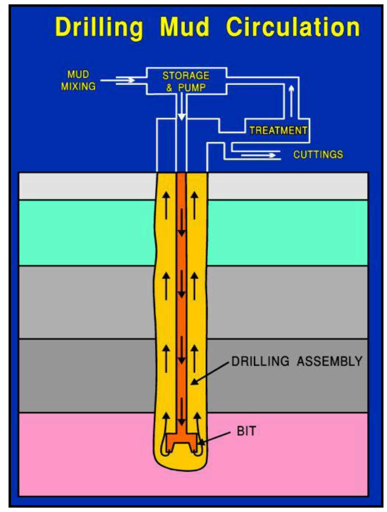
- Approval to Drill a Well (ADW)
  - Formation Pressure and Fracture Gradient Evaluation
  - Barrier analysis to confirm two barriers at all times
  - Casing Program
  - Cementing Program
  - Drilling Fluids
  - Casing and Wellhead Pressure Testing
  - Formation Leak-Off Tests
  - BOP Configuration
  - BOP Pressure and Function Testing

Safety Plans

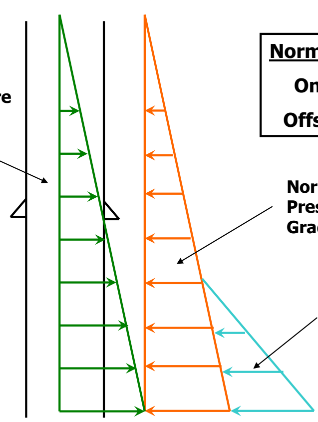
- Hazard Identification
- Risk Management
- Training and Competency of Personnel
- Details of Systems and Equipment, including Maintenance/Inspection/Testing
- Operational Procedures and Processes
- JOHSC
- Incident Reporting and Investigation
- Management Oversight/Monitoring

Oversight of Drilling Operations

- At Operations Application Level
- At ADW Submission/Review
- During Operations
  - Daily Drilling, Geologist and Log Reports
    - Reviewed by a number of C-NLOPB Staff
    - Copies provided to NL Dept of Natural Resources for Exploration and Delineation Wells
  - Inspections
  - Audits

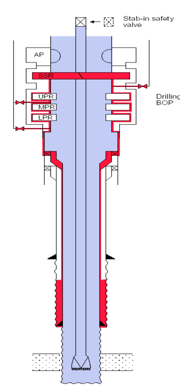


Formation Pressures



Normal Pressure Gradient
Onshore: 9.8 kPa/m
Offshore: 10.25 kPa/m

Well Barriers



Well barrier elements	See Table	Comments
Primary well barrier		
1. Fluid column	1	
Secondary well barrier		
1. Casing cement	22	
2. Casing	2	Last casing set.
3. Wellhead	5	
4. High pressure riser	26	If installed.
5. Drilling BOP	4	

BOP Specific Requirements

- BOP Stack Configuration and Operating Limits
- Capacity and Redundancy in BOP Control System
- Deepwater considerations
  - Hydrates
  - Cold Temperature
- Pressure and Function Test Procedures and Frequency
- Test Verification via review of Daily Report Information and records review during Audits
- Modes of Activation
  - 1 of 3 backup systems in shallow water (anchored vessel)
  - 2 of 3 systems in deep water (dynamically positioned vessel)

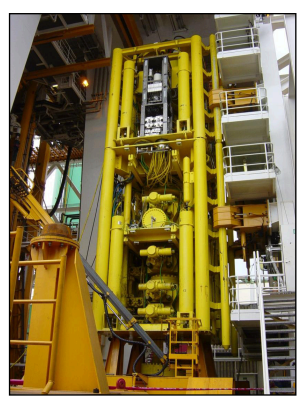
Riser Specific Requirements

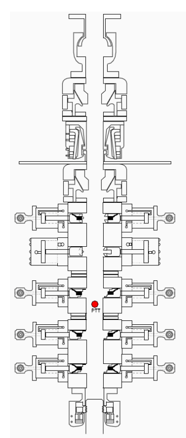
- Drillsite specific Riser Analysis and Weak Point Assessment
- Riser Margin
- Emergency and Planned Disconnect Procedures
- Drift-Off Management

Stena Carron

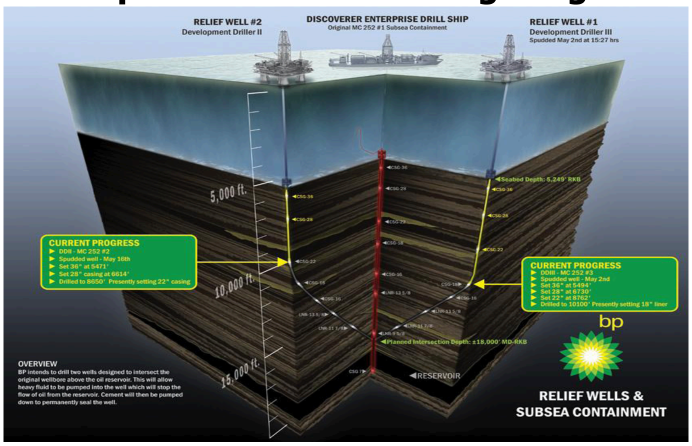
- Dual-mast, ultra-deepwater, dynamically-positioned drillship
- Drilling water depth of 10,000 ft
- Total drilling depth of up to 35,000 ft
- 3 backup systems for BOP activation
- Length of 748 ft.
- Variable Deck Load: 15,000 tonnes
- Maximum P.O.B.: 180 Man Accomodation
- 3 Electric Hydraulic Knuckleboom Cranes

Stena Carron - BOP Stack





Sample Relief Well Drilling Program



Source: http://www.deepwaterhorizonresponse.com/go/doctype/2931/54691/Horizon May 24, 2010 Update

Additional Oversight - Orphan Well

- Oversight Team established
- Field reports on testing activity
- Monitor DWH developments for lessons learned
- Audits and inspections every three to four weeks.
- Operations time-out
- C-NLOPB observer at specific times during the drilling program
- Spill response ready for rapid deployment before penetrating targets
- Review well termination program

IRF and NSOAF Best Practices

- International Regulators Forum
  - CNLOPB part of IRF
  - IRF committee activity
  - Upcoming IRF conference (program changes) and IRF meeting
- North Sea Offshore Authorities Forum – Wells Working Group
  - Well Operations Engineering meeting in Norway
  - Member country responses to GoM (not enough info available to define immediate and root causes about what happened)

BOP Back-up Systems on Mobile Drilling Installations in NL Offshore

- Stena Carron
  - ROV intervention
  - Automode Function
  - Acoustic System
- GSF Grand Banks
  - ROV intervention
- Henry Goodrich
  - ROV intervention

Henry Goodrich

Production Installations

- Drilling activity regulated same as exploration wells
- Different systems in place for production
  - Two Barriers
  - Production Tree
  - Downhole Safety Valve

C-NLOPB Spill Response Role

- **Operators Responsible for Emergency Response**
- **Lead government agency for drilling, production installations on site, e.g.:**
  - Hibernia, Terra Nova, White Rose production platforms, subsea installations, loading systems
  - Drilling units on site (e.g., Stena Carron at Lona O-55)
- **Resource agency in all other cases, e.g.:**
  - Drilling unit off-site
  - Supply vessels
  - Shuttle tankers

Interaction with Other Agencies

Accord Act paragraph 46 (1):

The Board shall, to ensure effective coordination and avoid duplication of work and activities, conclude with the appropriate departments and agencies . . . Memoranda of understanding in relation to (a) environmental regulation; (b) emergency measures; . . . and (f) such other matters as are appropriate.

- MOUs concluded in late 1980s with environment, fisheries, energy departments of Canada & NL
- Environment MOU acknowledges and cites the role of Regional Environmental Emergency Team (REET)

Regional Environmental Emergencies Team (REET)

- Formed by federal Cabinet directive following 1970 *Arrow* tanker spill
- REET provides consolidated environmental advice to lead agency and/or incident command
- Chaired by Environment Canada
- Members from federal, provincial agencies with environmental emergency related responsibilities
- Separate REET in each region of Canada
- Each REET meets annually in workshop mode
- REET can be activated in an emergency, with active participants drawn from membership

Spill Response Requirements

- All spills prohibited
- Contingency plans required
  - Also annual field countermeasures exercise
- Operator must report spills to C-NLOPB
- Operator must take "all reasonable measures" to respond to and mitigate spill
- Operator financially responsible for all "actual loss or damage" resulting from spill
  - Up to prescribed limit, without proof of fault or negligence
  - Unlimited liability where fault or negligence proved
- C-NLOPB Chief Conservation Officer has authority to intervene in response

Financial Responsibilities Requirements

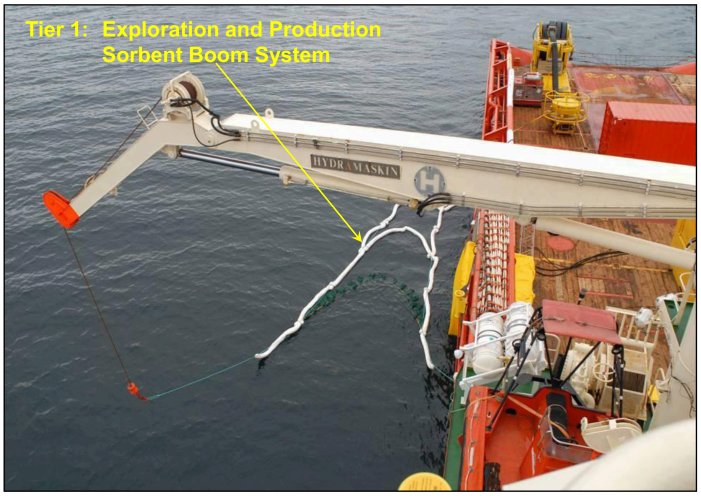
- Polluter Pays (Clean-up and Compensation)
  - $30 M direct access
  - $70 M available
  - $250 M financial capability

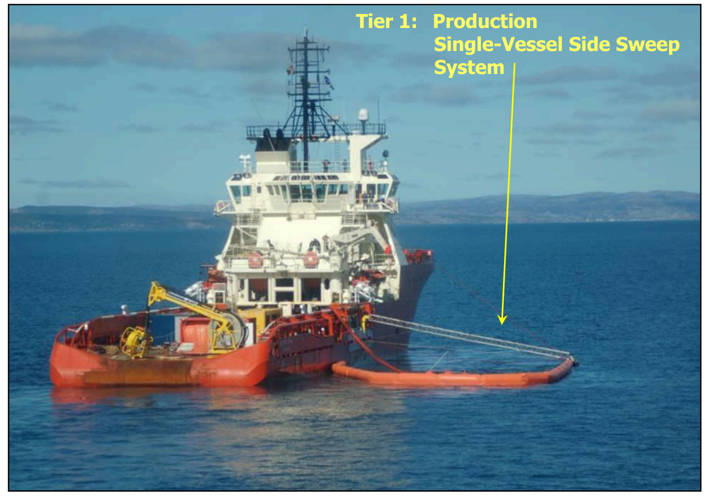
Spill Response – Typical Planning Elements

- **Tiered Response Structure**
  - Tier 1: In-field / at-site resources
  - Tier 2: NL / regional resources (e.g., ECRC, CCG NL)
  - Tier 3: National/international resources (e.g., OSRL)
- **Command/Control Structure**
- **Communications/Notification Procedures**
- **Identification of Resource Personnel and Organizations**
- **Provision for Personnel Training**
- **Resource Sharing Arrangements with Other Operators**

Oil Spill Response: Tier 1

- All Support Vessels: Exploration and Production
  - 100+ m Sorbent Boom
  - GPS/Satellite spill tracking buoys
  - Spill sampling kit
- In-Field Resources, Each Production Site
  - Single-Vessel Side Sweep (SVSS) system
    - 60 m of 2.1m boom
    - Weir skimmer [100 m^3/hr capacity (15,000 bbl/d)]
    - Outrigger arm





Oil Spill Response: Tier 2 and 3

- Tier 2: Regional Capacity
  - ECRC Donovans - available 24/7/365
  - CCG Donovans - available 24/7/365
  - Large–Capacity Skimmer Systems
    - Transrec 150 and 200 at ECRC, CCG
    - 53,000 bbl/d fluid throughput each
  - Unsheltered-Waters Boom Systems
    - 400 m Norlense 3.4 m boom (at ECRC)
    - 370 m NOFI 2.4 m boom (at ECRC)
- Tier 3 – Canada, International
  - Example: OSRL depot in Southampton, UK
  - Capable of responding anywhere in the world via cargo aircraft

Tier 2: Exploration and Production Norlense Boom

Tier 2: Exploration and Production Transrec Skimmer System

Information Disclosure

- Public Disclosure of Information
  - Oil Spill "Tombstone" Data
    - Per incident, for spills >1 liter*
    - Quarterly, for spills <= 1 liter
  - Environmental Effects Monitoring
    - Development drilling / Production*
  - Environmental assessment reports and documents
  - Contingency Plans
- Legislation
  - Section 119

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Appendix VIII

Regulatory Environment, Batch-spill Sources and Facility Spill Prevention (Prepared by Hibernia Management and Development Company and presented to Mark Turner and Justin Skinner on June 25, 2010)

Hibernia Management and Development Company Ltd.

Presentation to

Mark Turner

June 25, 2010

Presentation Outline

- Regulatory Environment
- Batch Spill Sources
- Facility Spill Prevention

Regulatory Environment

Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB)

The Newfoundland offshore oil and gas industry is a highly regulated industry.

- Detailed regulations and guidelines
- Work Authorization requirement
- Certifying Authority Fitness for Service verification
- Continuous monitoring by C-NLOPB
- Quarterly audits and compliance assessments by C-NLOPB and Certifying Authority (Lloyd’s Register)

Regulatory Environment

Regulatory Requirements

The Operator must submit plans, including the following, to the C-NLOPB for approval prior to obtaining authorization for exploration, development and production:

- Development Plan
- Canada-Newfoundland Benefits Plan
- Safety Plan
- Drilling Program
- Reservoir Depletion Plan
- Environmental Protection Plan

Regulatory Environment

Operations Authorization

C-NLOPB has provided HMDC with an Operations Authorization (approved every 3 years)

The primary safety documents required and approved by the C-NLOPB as prerequisites to the operations authorizations were:

- Concept Safety Analysis (design phase)
- Safety Plan (operational phase)

Regulatory Environment

Regulatory Oversight

C-NLOPB performs scheduled inspections and compliance audits of HMDC to ensure:

- compliance with all regulatory requirements
- compliance with conditions imposed by the Operations Authorization, including the safety plan

C-NLOPB Audits and Inspections Frequency

- Annual audits
- Quarterly inspections
- Ad hoc inspections as required

Batch Spill Sources

Batch Spill

- Unlike blowout scenario, a batch spill generally occurs over a period of minutes or hours

Potential Sources

- Produced water handling system
- Drainage water
- Iceberg impact (GBS and/or OLS damage)
- Ship impact (GBS damage)
- GBS ballast water

Facility Design

General Platform Safety Design

- Process Shutdown / Emergency Shutdown functions based on DCS
- Emergency Control System and Emergency Shutdown Valves
- Pressure Safety Valves and Flare Relief System
- Process instrumentation
- Fire and gas detection
- Fire suppression
- Blast walls

Facility Design

Produced Water Handling System Design

- Platform waste treatment systems treat regulated waste streams to ensure they achieve effluent specifications outlined in the C-NLOPB Offshore Waste Treatment Guidelines (OWTG)
- Water produced in conjunction with oil and gas is treated to remove entrained oil prior to discharge
    - Primary separation is achieved in Separators
    - Secondary separation is achieved in Hydrocyclones
    - Tertiary separation is achieved in Degasser Vessels
- System is equipped with instrumentation and controls monitored continuously in the DCS to ensure system is maintained within acceptable operating limits
- Within the DCS is logic to trigger a PSD or ESD if operating limits are not met

Facility Design

Platform Drains System Design

- The platform drains systems is designed to safely dispose of liquids drained from equipment or washdown from both topsides and GBS equipment. Any oil/oily water routed to drain is recovered and returned to the process system
- Oily water from the platform drains system is routed to the Oily Water Treatment Package
    - Consists of two centrifuge units
    - Recovers oil from water to reduce the OIW content to achieve effluent specifications outlined in the C-NLOPB Offshore Waste Treatment Guidelines (<15mg/l before disposal)

Facility Design

Iceberg Impact (GBS and/or OLS damage)

- The Gravity Based Structure (GBS), constructed of a 50-foot-thick concrete wall and 16 ice teeth, is designed to withstand the impact of icebergs
- The crude oil export line is made of heavy steel coated with concrete
- Platform radar system is equipped with an enhanced target acquisition and tracking capability to monitor ice conditions
- Air and boat surveillance for icebergs is completed during peak iceberg season
- The capability exists to tow or deflect icebergs that approach the platform
- The export lines and the OLS can be flushed (emptied of oil by filling with seawater) in the event of a threat of ice damage

Facility Design

Ship Impact (GBS Damage)

- GBS wall consists of a 50-foot-thick concrete belt and crude oil storage cells separated from the sea by the double wall
- Tankers maintain position within a confined watch circle and if it strays beyond these limits, loading automatically shuts down
- Facilities have a designated safety zone around the platform established by Transport Canada - Department of Fisheries and Oceans and the C-NLOPB. Prohibits all vessels, including fishing vessels, from entering the zone
- OLS is equipped with fail-safe coupling valves

Facility Design

GBS Ballast Water System Design

- Ballast water is used in both the storage and loading operations to maintain the pressure in the storage cells within an acceptable range by keeping the cells filled with liquid
- Levels in the storage cells are monitored in the DCS
- Equipped with hydraulically actuated ESV on the outlet, and if triggered will result in a production shutdown

Facility Operation

Hibernia Safety Plan Overview

- Hibernia Operational Plan has been approved by the C-NLOPB as meeting the requirements of a safety plan
- Based on the Concept Safety Analysis
- Formalizes Hibernia's commitment to operate in a safe and environmentally responsible manner
- Lays out the management system or framework under which we conduct our work
- Living document updated as needed to reflect operational changes and at a minimum every three years to maintain the Operations Authorization as approved by the C-NLOPB
- Updates require C-NLOPB approval prior to implementation
- The Operational Plan serves as a basis for audits by the C-NLOPB and the Certifying Authority

Facility Operation

Safety Management Systems

A safety management system provides a systematic approach to managing safety. The safety management system identifies hazards and ensures associated risk is eliminated or effectively managed. A typical safety management system includes:

- integrated organizational structures
- responsibilities and accountabilities
- policies and procedures
- measurement, feedback and continuous improvement processes

Facility Operation

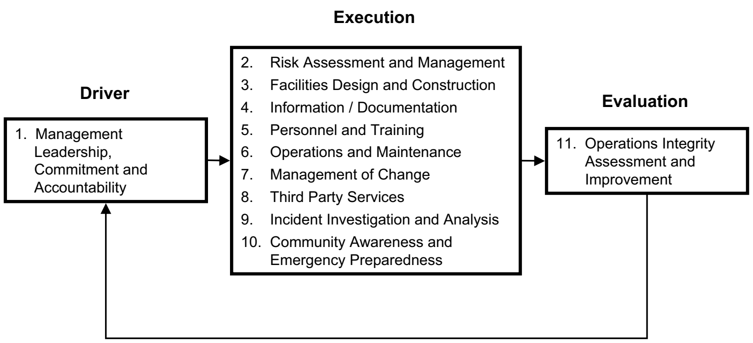
Operations Integrity Management System

- HMDC's safety management system is called the Operations Integrity Management System (OIMS)
- Systematic and structured approach to the management of safety, health, environment and security
- Focused on identifying hazards and managing risk
- A mature and globally tested system

OIMS Stewardship and Sustainment

- High level of management involvement and accountability
- Ensures safety and environmental compliance with applicable laws and regulations and drives continuous improvement
- Workforce participation is key to OIMS effectiveness
- OIMS is fully integrated into HMDC's operations and impacts all work activities

11 Elements of OIMS



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Appendix IX

Spill Prevention - Well Design, Well-control and Drilling

(Prepared by Husky Energy and presented to Mark Turner and Justin Skinner on June 25, 2010)

Spill Prevention – Well Design, Well Control and Drilling

Husky Energy

The Prevention of Well Control Incidents and Blowouts

- Companies offshore Newfoundland and Labrador prevent well control events through:
  - Compliance with Regulatory Requirements
  - Certified Equipment
  - Thorough Processes (Planning and Execution)
  - Proper Training of Personnel
- The Focus is on Prevention

Regulatory Requirements

- Operators are required to have Management Systems in place which ensures compliance with the C-NLOPB regulatory requirements.
- Drilling facilities, including Mobile Offshore Drilling Units (MODU's), for use offshore Newfoundland and Labrador must hold a valid Certificate of Fitness (COF), issued by an independent certifying authority, indicating that the rig meets all requirements set forth by the C-NLOPB.
- In addition the MODU must hold a valid Letter of Compliance (LOC) from Transport Canada.
- During their operating lives the facilities are subjected to Special Periodic Surveys (SPS) during which time critical systems, including well control systems, are overhauled and re-certified. The frequency and scope of these surveys varies.
- Prior to engaging in drilling operations, each Operator must receive from the C-NLOPB an Operations Authorization which addresses each of the points above.
- Site Surveys are performed to ensure that drilling locations are free of seafloor obstructions and shallow hazards.
- Each well design is submitted to the C-NLOPB who issues an Authority to Drill a Well (ADW) to the Operator. This is in essence a license to proceed with drilling operations on that well.
- The C-NLOPB has the right to audit all aspects of any operation at any time.

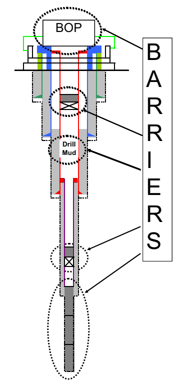
Well Design

- The Subsurface Department submits a reservoir target and objectives to the Drilling and Completions Department
- The Drilling and Completions Department designs a well to reach the reservoir target and meet the well objectives
- The Operations Department provides input and may suggest changes to the well design
- Service companies review program that the objectives can be achieved with their specialists and specialty equipment
- Consensus is reached on the plan and a formalized Well Program is generated for the Operations Team to follow in the Well Construction Process

Well Design

- Each section of the Well Program is designed to achieve its objective with minimal risk
- The well is designed to be drilled, tested and suspended without having to use the Blowout Preventer (BOP) for well control
- The well is designed to balance wellbore pressures with fluid hydrostatic pressure – Primary Well Control
- At least two barriers are in place at any one time to ensure primary well control is maintained.

Typical Wellbore Barriers



Levels of Well Control

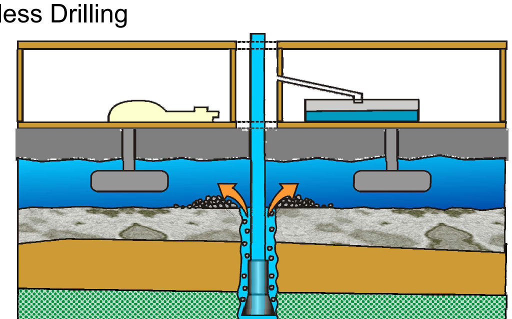
Primary: Maintain a drilling fluid hydrostatic pressure greater than formation pressure

Secondary: Blowout preventers (BOP's) are used to control the well – Key personnel undergo refresher training every two years

Tertiary: The blowout preventers cannot be used to control the well – drilling a relief well is tertiary well control

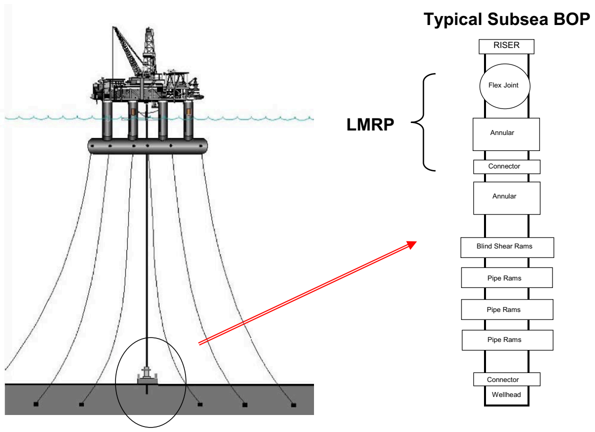
Note: Except for riserless drilling, there are two barriers to pressure maintained for all drilling and completion operations.

Riserless Drilling



1. Specific site surveys are conducted to detect the presence of shallow gas. In 2005 the Lewis Hill well location was changed to avoid potential shallow gas.
2. The rig can be skidded away on the anchor chains if gas is encountered.
3. The first two hole sections are typically drilled with returns to the seafloor.

Typical Subsea Arrangement



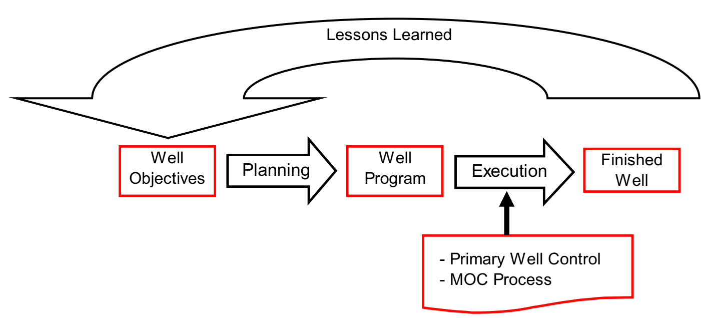
BOP Shut-In Options

Pipe Profile in BOP	Options to Secure Well			Comment
	Annulars	Shear Rams	Pipe Rams	
Drill pipe body	Yes	Yes	Yes	Annulars are normally used to shut in wells because they can seal on any profile.
Drill pipe connection	Yes	No	No	
Drill collar	Yes	No	No	
Casing up to 244 mm	Yes	Possible	Possible	BOP's can be configured with pipe rams for casing up to 244 mm. Shear ram capacity depends on grade and weight of casing.
Wireline	Yes	Yes	No	
No pipe in hole	Yes	Possible	No	Shear blind rams can secure a well but simple shear rams cannot.

Health, Safety and Environment Culture

- All changes which are made after the Well Program been issued are risk-assessed and documented through a Management of Change (MOC) process
- Daily meetings assess in detail the next 24 hours of operations
- Risk assessments and safety meetings at key points throughout the well construction operation (for example – prior to running casing)
- Individuals are empowered to shut down the operations at any time if safety appears to be an issue.
- A behaviour-based safety reporting system is in place on all offshore drilling facilities. (STOP, START, FOCUS)
- Drills are held frequently and are designed to keep crews alert to the potential of well control events and to reinforce operational proficiency.

Summary of Typical Offshore Well Design and Execution



Review of Offshore Oil-spill Prevention and Remediation Requirements and Practices in Newfoundland and Labrador

December 2010

Appendix X

Oil-spill Preparedness and Response Overview (Prepared by Suncor Energy and presented to Mark Turner and Justin Skinner on June 25, 2010)

Oil Spill Preparedness and Response Overview

Presentation to Captain Mark Turner

June 25, 2010

Oil Spill Preparedness and Response

- Oil spill preparedness and response is one component of an Operator's overall management system that is in place to ensure safe and environmentally responsible operations
- Although the ability to respond to any emergency situation, including an oil spill, is critical, an Operator's priority is to ensure process and engineering controls are in place and effective to prevent occurrence of the event

Oil Spill Preparedness

- To prepare for potential events, Operators develop extensive oil spill preparedness and response programs that include:
  - Risk identification and assessment of potential spill scenarios
  - Understanding of the regulatory requirements
  - Detailed Oil Spill Response or Contingency Plans
  - Definition of roles and responsibilities, including response management structure, both offshore and onshore
  - Operational preparations and procedures, including training and exercise requirements for responders
  - Contracts with response organizations (e.g., ECRC and/or OSR)
  - Availability and maintenance of response equipment
  - Processes to review/enhance response capability as necessary

Oil Spill Preparedness – Response Plans

- All Operators have detailed Oil Spill Response Plans that are reviewed by the C-NLOPB during Authorization application
- The Plans contain the following elements:
  - Spill Response Objectives and Strategies
  - Regulatory Considerations
  - Response Management, Roles and Responsibilities
  - Internal and External Communication Requirements
  - Response Countermeasures for Oil Spill Scenarios
    - Equipment, Personnel and Processes/Techniques
  - Waste Management
  - Training and Exercise Requirements

Oil Spill Preparedness – ECRC

- Preparedness Agreement between production operators and Eastern Canada Response Corporation (ECRC)
  - Regular training and exercises for Tier 1 and Tier 2 oil spill responders, including vessel crews and ECRC
  - Inspection and maintenance programs and for Tier 1 and Tier 2 oil spill response equipment
  - Oil Spill Response Plan review and update on annual basis
  - Logistics support for the Suncor Seabird Cleaning and Rehabilitation Centre
  - Participation and support of oil spill response exercises
  - Storage for Tier 1 and Tier 2 oil spill response equipment
  - Technical advice on equipment purchases and oil spill response process changes

Oil Spill Preparedness – Joint Industry

- Joint Industry Preparedness and Response
  - Oil Spill Response Committee with Basin operators to review and identify continual improvement opportunities for oil spill response equipment and processes
  - Annual On-Water Oil Spill Countermeasures Synergy Exercise
  - Mutual Emergency Assistance Agreement with other Basin operators

Oil Spill Response – Tiered Response

- Operators have developed the following three-tiered oil spill response structure that enables them to effectively respond to different types of events
  - Tier 1
    - Equipment and resources that are maintained offshore on either the installation or support vessel
  - Tier 2
    - Equipment and resources that are maintained onshore in St. John's that can be mobilized to support the offshore response
  - Tier 3
    - Equipment and resources that are not available locally but that can be accessed nationally or internationally

Oil Spill Response – Tier 1

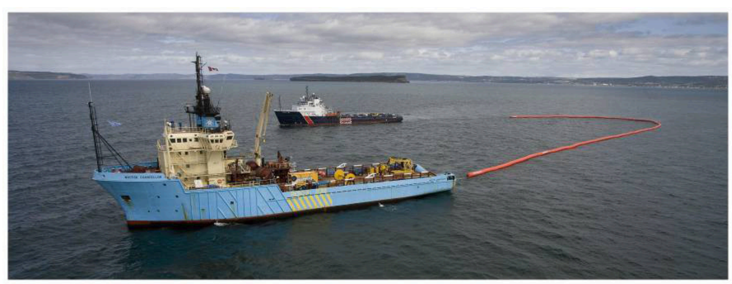
- Tier 1 Equipment and Resources
  - Sorbent side sweep materials (boom, pom poms, etc.)
  - Single Vessel Side Sweep (SVSS) system on production installations (i.e., Hibernia, Terra Nova and SeaRose)
  - Oil observation equipment
  - Seabird recovery equipment
  - Tracker buoys
  - Sampling kits
  - Installation and vessel crew who have been trained in Tier 1 oil spill response countermeasures

Single Vessel Side Sweep (SVSS) System (Synergy 2009)

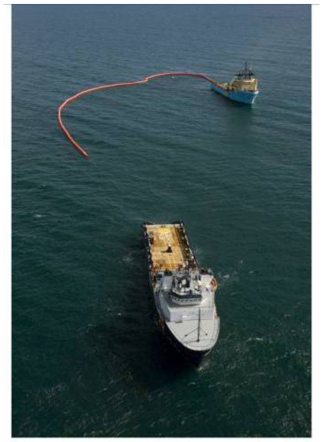
Oil Spill Response – Tier 2

- Tier 2 Equipment and Resources
  - Tier 2 response and spill management for all offshore installations is provided under contract by the Eastern Canada Response Corporation (ECRC), a Transport Canada-certified Response Organization
  - Framo Transrec 150 Skimmer System and associated equipment (Operator-owned)
  - NorLense 1200-R Self-Inflating Offshore Boom and associated equipment (Operator-owned)
  - Other ocean-going booms, skimmers, vessels, barges, etc. that are available through ECRC

NorLense 1200-R Boom Deployment (Synergy 2009)



NorLense 1200-R Boom Deployment (Synergy 2009)



NorLense 1200-R Boom Deployment (Synergy 2009)

Transrec 150 Skimmer (Synergy 2009)

Transrec 150 Skimmer in Apex of NorLense 1200-R Boom (Synergy 2009)

Oil Spill Response – Tier 3

- Tier 3 Equipment and Resources
  - Tier 3 response and spill management for all offshore installations is provided under contract by the Oil Spill Response in the United Kingdom
  - Dispersant capability through aircraft
  - Ocean-going booms, skimmers and associated equipment
  - Technical advisory service to support oil spill response
  - Access to OSR's Global Response Network in the event of a major event
  - Access to the global oiled wildlife response service support
- Access to Corporate response teams who can provide expert advice and support during an emergency event

Oil Spill Response – Seabirds

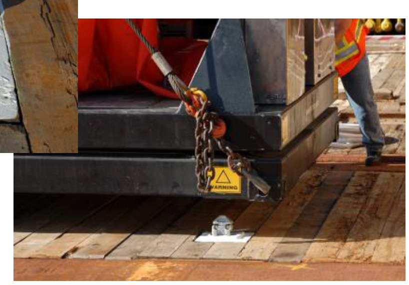
- Seabird Cleaning and Rehabilitation Centre
  - Operated by Suncor and Husky
  - Access to Centre by other offshore operators
  - On call veterinarian and trained responders
  - Permitted through the Canadian Wildlife Service and the provincial Department of Environment and Conservation

Oil Spill Response Capability Report

- In November 2009, producing operators (HMDC, Husky and Suncor) submitted an Oil Spill Response Capability Report to the C-NLOPB
- The scope of the Capability Report included:
  - The range of meteorological and oceanographic conditions on the northeast Grand Banks
  - The nature of spill scenarios that are reasonably foreseeable in association with Grand Banks production operations;
  - The condition and operability of existing equipment currently available to operators in eastern NL
  - The degree to which additional or alternative equipment available may enhance existing response capability

Capability Report – Recommendations

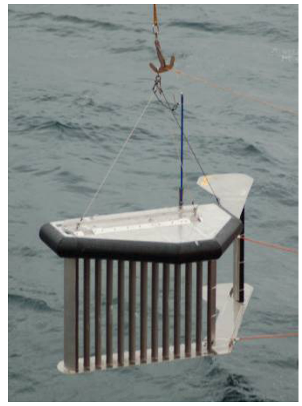
Further Capability Enhancements	Actions to Date
Norwegian Standard System (Norlense 1200-R Boom and FRAMO Transrec 150 Skimmer)	• NSS equipment purchased in June 2009 by HMDC, Husky and Suncor • Commissioned in September 2009 • Demonstrated in Synergy 2009 • Chevron Exercise in June 2010 • Procurement of another NSS planned for 2010
Deployment and Mobilization	• Husky has installed ISO mounts on one vessel and currently installing on a second vessel • Chevron has installed ISO mounts on one vessel • Suncor conducting MOC assessment for installation of ISO mounts on two vessels in 2010 • HMDC considering installation of ISO mounts on two vessels pending a feasibility analysis in 2010



Vessel ISO Mounts

Capability Report – Recommendations

Further Capability Enhancements	Actions to Date
Other Equipment	• Husky currently looking to purchase an Ocean Boom Vane in Q3 or Q4 2010 • Suncor conducting MOC assessment for purchase of Ocean Boom Vane in 2010
Dispersants	• Dispersant testing has been conducted on Hibernia, White Rose and Terra Nova crudes • CAPP commissioned S.L. Ross to complete a NEBA study on dispersants • Recognize more work is needed – regulatory and project to assess dispersant options
Joint Operator Steering Committee	• Representatives from HMDC, Husky and Suncor meet on a monthly basis to discuss response



Ocean Boom Vane Trial (2009)

Capability Report – Recommendations

Further Capability Enhancements	Actions to Date
ECRC Integration	• Husky and Suncor signed an oil spill preparedness integration agreement in November 2009 that covers maintenance and training for Tier 1 and Tier 2 oil spill response equipment • Activities for Husky and Suncor started in February 2010 • HMDC working to sign a new contract to include equipment training and maintenance with ECRC in 2010
Research and Development and Education and Training	• Operators are currently discussing research and development and education and training opportunities associated with oil spill response • To date, no projects have started or expenditures have been made

Conclusions

- Safety and Environmental Protection are Top Priorities
- Offshore Oil and Gas is a Highly Regulated Industry
- Risk Management and Oil Spill Prevention and Response
- Continual Improvement and Lessons Learned
- Additional Information from Industry

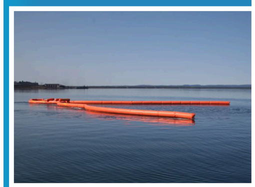
Review of Offshore Oil-spill Prevention and Remediation Requirements and Practices in Newfoundland and Labrador

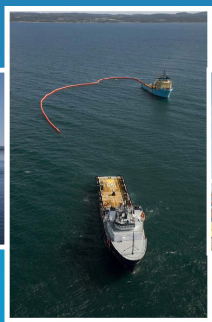
December 2010

Appendix XI

ECRC-SIMEC Overview (Prepared by ECRC in June, 2010)

ECRC~SIMEC Overview


NOFI current buster


NOFI 1000 V-Sweep


Transrec 150 skimmer

Presentation Topics

- Origin Of Response Regime
- ECRC Overview
- Response Equipment
- Training
- Exercises
- Area Response Plans
- Spill Management System (SMS)
- LSEP – (Land Spill Emerg. Prep.)
- ECRC Services to the Offshore

Origin of Response Regime


⇐ Nestucca, 1988

Exxon Valdez, 1989 ⇒

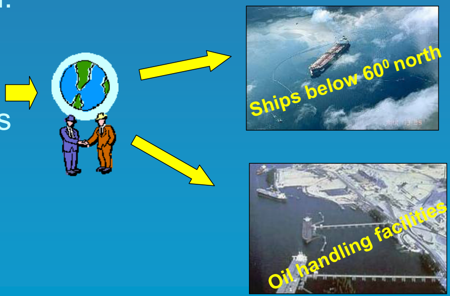


⇐ Increased public concern

Origin of Response Regime

Changes in the Canadian Shipping Act resulted in:

Response Organizations



Origin of Response Regime

Some Key Differences from American System

- Canadian RO's are required to provide an operational management component for SMT activities
- Provide equipment and trained responders
- Maintain Area Response plans for our geographic areas of response

Origin of Response Regime

Some Key Differences from American System Cont'

- RO membership is Legislated as opposed to voluntary
- Certification Versus Classification
- Dedicated equipment versus a combination of dedicated and non-dedicated

Presentation Topics

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- ECRC Services to the Offshore

ECRC Organization

- Private Corporation
- Industry shareholders
  - Imperial Oil
  - Shell Canada
  - Suncor
  - Ultramar
- Existing preparedness programs
  - Marine Spill Preparedness (Canada Shipping Act 2001)
    - Oil Handling Facilities and Ships (as prescribed in CSA 2001)
    - Preparedness for Offshore Operators
  - Land Spill Preparedness
    - Tank trucks and rail cars

ECRC Mission

- Maintain a state of marine oil spill preparedness that is consistent with the legislation and capable of providing a real response at an affordable cost to our members
- Provide value added preparedness services to all of our members
- Assume a leadership role in the preparedness to oil spill response within the community at large

ECRC CLIENTS

- Total of 2500 Members
  - 2416 Marine Members
  - 74 Oil Handling Facilities
  - 10 Subscribers (pay an annual fee for ECRC services)

  Enbridge Pipelines, Montreal Pipe Line Ltd., Hibernia Mgt & Dev. Co. Ltd, Husky Oil, Suncor – Terra Nova, Hydro One Networks Inc., Hydro-Québec, Nova Chemicals (Canada) Ltd., IOL Pipe Line, CN

ECRC Certification


Transport Canada Transports Canada

This attests that / Ceci atteste que

Eastern Canada Response Corporation Ltd
Société d'intervention maritime, Est du Canada Ltée

is a Certified Response Organization pursuant to section 169.(1) of the *Canada Shipping Act, 2001*

est un Organisme d'intervention agréé en vertu de la section 169.(1) de la *Loi de 2001 sur la marine marchande du Canada*

Maximum capacity of / Capacité maximale de

10,000 Tonnes

Geographical Area of Response

Canadian waters south of 60°N latitude in the provinces of Newfoundland, Prince Edward Island, Nova Scotia, New Brunswick, Québec, Ontario, Manitoba, Saskatchewan and Alberta, excluding the waters in the primary areas of response associated with the designated ports of Saint John, N.B. and Point Tupper, N.S.

Secteur géographique d'intervention

Les eaux canadiennes au sud du 60° parallèle de latitude nord dans les provinces de Terre-Neuve, de l'Île du Prince Edouard, de la Nouvelle Ecosse, du Nouveau Brunswick, du Québec, de l'Ontario, du Manitoba, de la Saskatchewan et de l'Alberta, excluant les eaux du secteur primaire d'intervention pour les ports designés de St. John, N.B. et Point Tupper, N.S.

Director General - Marine Safety - Directeur général - Sécurité maritime

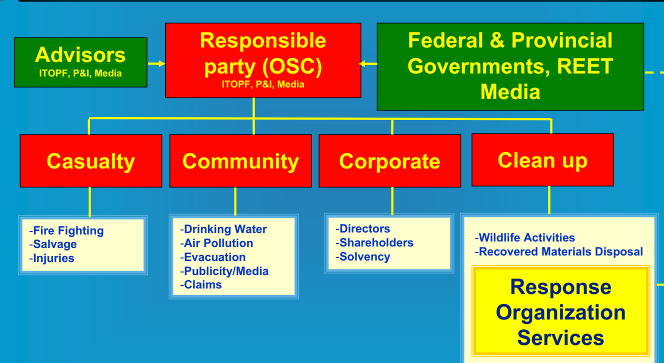
OTTAWA
Issued at - Délivré à

NOV 1st 2010
Expiry date - Date d'expiration (dd-mm-yyyy / jj-mm-aaaa)

81-0024 (0710-02)

Canada

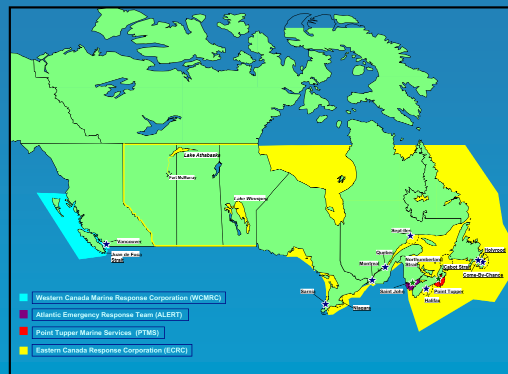
ECRC-RP Relationship



Response Services

- On-water recovery
- Sensitivity identification / protection
- Shoreline protection
- Shoreline treatment
- Recovered materials segregation
- Bird scaring

Four Response Organizations



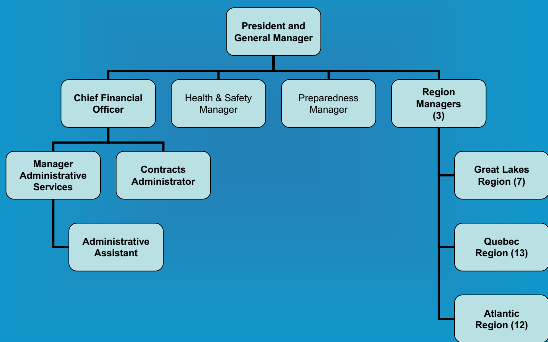
ECRC Response Centers

ECRC Certification

How does ECRC meet Transport Canada's requirement for 10,000 Tonnes of Response Capability?

Corunna, ON - 2500 Tonnes
Vercheres, QC - 2500 Tonnes
Quebec City, QC – 2500 Tonnes
Sept Isle, QC – 2500 Tonnes
Halifax, NS – 2500 Tonnes
St. John's, NL – 3500 Tonnes

ECRC National Structure



Presentation Topics

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- ECRC Services to the Offshore

ECRC National Inventory

Boats: 100 plus

Booms: Sheltered water 54,000 m

Unsheltered water 6,000 m

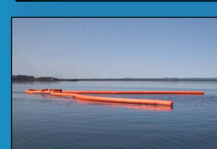
Skimmers: 100 plus (Various Capacities, Manufacturers, Sizes)

Storage: Solid barges 34 (13,000 m^3 capacity)
Flexible barges 30 (3,000 m^3 capacity)

* NOTE: Most equipment is road transportable and most is found on trailers to allow cascading to other regions for enhanced response capability.

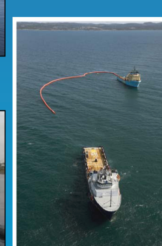
Sweeps Systems

14 Systems Total



Buster Systems
Ocean, Current and Harbour

NOFI 1000 & NOFI 600 Systems



Norlense 1200

Vikoma Boom

RO Boom

Response Center Equipment

Inside St. John's Response Center Warehouse

Equipment Readiness

- Preventive maintenance program
  - In place for all equipment
  - Records maintained in database

Presentation Topics

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Contractor Training Program

- Modular Training Approach
- 3 operating environments

Unsheltered waters

Sheltered waters

Shoreline

ECRC Responders

- 552 Responders
  - 77 Great Lakes
  - 235 Québec
  - 240 Atlantic
- 80 plus Advisors
  - 10 National
  - 70 plus Regional
- 38 ECRC Personnel

Advisor Training Program

- Hire individuals with specific skills
- Trained to perform within RO procedures and structure
- 20-25 per response center, fill SMT roles in Planning, Logistics, Operations and Health and Safety
- Work for ECRC function managers

External Training

- Client oriented response training
  - OHF (oil handling facilities)
  - Vessel crew training
  - Offshore operator training

Presentation Topics

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Exercise Program

- Recognizes concepts of National Exercise Program
- Demonstrates equipment deployment / operation capabilities (Type II)
- Demonstrates operational management capabilities (Type III and IV)

Types of Exercises

Type I:	Notification	Quarterly per PAR
Type II:	Operational	Annually per PAR
Type III:	Operational management (level 2 / 3 response)	Once during certification period per PAR
Type IV:	Operational management (level 3 / 4 response)	Once during certification period per Region

* Actual responses may be credited as exercises

Presentation Topics

- Origin Of Response Regime
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- ECRC Services to the Offshore

Area Response Plans

- Key component of preparedness
- Provide guidance for response to 32 specific areas within GAR (Geographic Area of Response)
- Contents:
  - Equipment mobilization / time charts
  - Personnel mobilization procedures
  - Logistics data (operations centres, boat ramps, docks, staging sites, maintenance sites, field ops / comm sites, etc.)

Area Response Plans

- Support documents:
  - Manuals:
    - -Countermeasures Requiring Approval
    - -Logistics Resource
    - -Sinking Oil
  - Catalogues:
    - Generic and specific field missions

Area Response Plans

- Sensitivity Mapping Program:
  - Partnership with Environment Canada
- Data available:
  - Digitized base maps
  - Shoreline segmentation
  - Pre-spill database
  - Sensitivities
  - Logistics data

Presentation Topics

- Origin Of Response Regime
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Spill Management System

- Based on National Interagency Incident Management System (NIMS)
- More commonly referred to as ICS (Incident Command System / Structure)
- Provides common terminology / documentation and is specific to Oil Spills

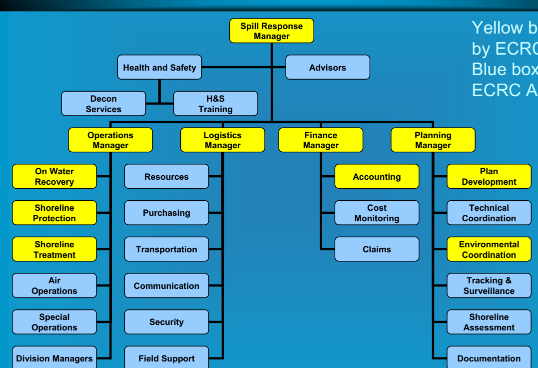
Spill Management System

- Consistent functional structure
- Common plans of action
- Works with any type of NIMS-based management system

Spill Management System

- Spill Management Team (SMT) starts small and expands as necessary
- Consists of ECRC managers and Response Advisors.
- Allows SMT to move from a “reactive mode” to a “proactive mode” as quickly as practical

Functional Management



Yellow boxes filled by ECRC Managers, Blue boxes filled by ECRC Advisors

Activation

- Emergency notification: (613) 930-9690
- Region duty pagers (2)
- Activate required contractors
- Activate required ECRC Regional personnel
- Notify/ activate other ECRC regions
- Management System initiated

Presentation Topics

- Origin Response Regime
- ECRC Overview
- Response Equipment
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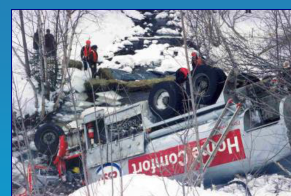
- Spill Management System (SMS)
- Land Spill Emergency Preparedness - LSEP
- ECRC Services to the Offshore

Land Spill Emergency Preparedness / Response


Inverness 2001


Big Interval 2002

LSEP/R

- Focus on oil spills originating from road and rail transportation accidents
- CPPI Funding Committee sets standards and provides direction
- ECRC implements both preparedness and response

ECRC Responsibilities

Preparedness

- Identification of response contractors
- Contractor training and exercising
- Facilitate equipment maintenance through contractors
- Auditing of contractors where applicable

Response

- Provide dispatching services
- Provide incident management as required / requested

Presentation Topics

- Origin Of Response Regime
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- Exercises
- Area Response Plans
- Spill Management System (SMS)
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- ECRC Services to the Offshore

ECRC Services to the Offshore

- Contracts for bulk & non-bulk ships (CSA 2001)
  - Drill ships / Rigs in transit
  - Seismic vessels
  - Supply vessels
  - First-leg tankers
- Offshore operator agreements
  - Drill ships / Rigs while drilling
  - Offshore production platforms

ECRC Services to the Offshore

- Access to all the equipment inventory that satisfies CSA
- Offshore operator supply vessel crew training for Single Vessel Side Sweep Systems and Sorbent Sweep Systems
- Offshore responder training (NL) for 20 ECRC responders for deployment of Offshore Response Equipment
- Offshore operator exercise development and coordination (NL)

ECRC Services to the Offshore

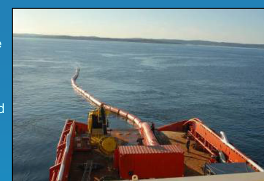
- Storage and Maintenance of Offshore Response Equipment Including:
  - Transrec 150 System
  - NorLense 1200 Containment System
  - Single Vessel Side Sweep System (SVSS)

ECRC Services to the Offshore

- Additional Services to the Offshore:
  - Responsible for sorbent inventories, sampling kits, tracker buoys, and bird recovery equipment on Suncor and Husky supply vessels
  - Logistical support for bird rehabilitation center in St. John's

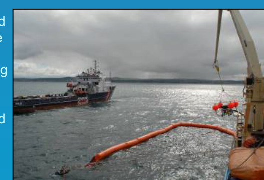
ECRC Services to the Offshore

Large Offshore boom system being deployed



Large NorLense 1200 boom systems being deployed from supply vessel

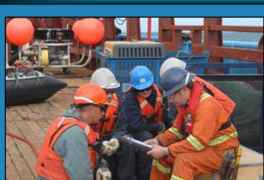
Standard Offshore SVSS skimming system being deployed from supply vessel.

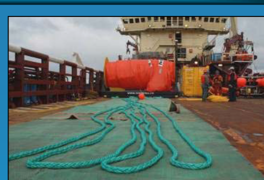


Tranrec 150 skimmer ready for deployment from the deck of a supply vessel

ECRC Services to the Offshore

Safety is always 1st, Here a crew is reviewing safety plan before deploying offshore skimming system





Supply vessel with large NorLense 1200 offshore sweep system ready for deployment

supply vessel with standard sorbent sweep system deployed

Supply vessel with a large Ro-Boom sweep system deployed

Review of Offshore Oil-spill Prevention and Remediation Requirements and Practices in Newfoundland and Labrador

December 2010

Appendix XII

David Pryce Presentation to House of Commons Standing Committee on Natural Resources (Prepared by CAPP and presented on May 13, 2010)

Representation to the Standing Committee on Natural Resources
May 13, 2010
Study of Emergency Response Assets and Adequacy of the Current Regulatory Regime of Offshore Oil and Gas Drilling and Production in Canada

General

- CAPP represents more than 100 companies that produce about 90% of Canada's natural gas and crude oil as part of a $110 billion a year national industry.
- As a Canadian Association we are able to provide broad industry views on policy and regulation, as well as information on the state of the industry. We are not able to comment on the circumstances of the Gulf of Mexico incident or the U.S. regulatory regime. Nor are we able to speak to specific company plans.
- CAPP appreciates the opportunity to convey initial thoughts both on Emergency Response Assets and on the current Policy and Regulatory Regime for offshore oil and gas drilling and production as noted in this Committee's invitation to CAPP to appear.
- We are also prepared to contribute further information as may be required or useful as this Study proceeds.
- CAPP and its members believe that the incident in the Gulf of Mexico is a tragic and unfortunate event. It is in the interest of all stakeholders that we collectively take time to consider the findings and recommendations arising from the investigation of this incident. This measured approach will allow us to fully understand the circumstances under which this incident occurred and assess whether there is an opportunity to improve our regulatory system and/or industry operating practices in Canada.
- Canadians, Governments and Industry all have a vested interest in achieving the right outcomes from this Study.
- Our key themes for this Study are as follows:
    - As context, the International Energy Agency projects world energy demand to grow by 40% over the next 20 years with crude oil and natural gas expected to meet 40% of that growth in demand.
    - Global offshore crude oil production represents about 38% of the world's energy supply. Canadian offshore crude oil production represents about 12% of Canada's crude energy supply.
    - The offshore regulatory regime and industry operating practices have evolved over a number of decades, resulting in a robust regulatory system in place today.
    - All forms of energy development pose environmental and safety risks. The challenge for government policy, regulators and industry collectively is to take reasonable measures to mitigate the risks such that incidents are unlikely to occur, and to be prepared to respond to any such incident.
    - Take the time to learn from the Gulf incident prior to determining if regulatory changes are required.

Emergency Response Assets

- The question of emergency response assets, we believe, should be targeting an understanding of both preventive measures and preparedness measures.
- Both Governments' and Industry's focus is on prevention first. That means understanding the risks and the measures that can be taken to control risks.
- Industry approaches all activity with a goal to complete the activity without incident or injury. Risk is assessed and mitigative measures are applied to achieve a risk level that is as low as is reasonably practicable without eliminating the possibility of conducting an activity. Companies propose these risk management strategies as part of their application which is then subject to the judgment of acceptability by the regulator.
- In addition to meeting corporate and regulatory expectations with respect to prevention, companies must also demonstrate capability to respond to any incident with a view first to containment and ultimately recovery and clean-up.
- Response capability means ensuring access to necessary equipment.
- It also means ensuring an effective management system, typically referred to as an Incident Command System, which integrates companies and regulatory agencies to provide and define leadership responsibilities and execution throughout the duration of an incident.
- Training is a key component of competent response capability, and companies are required to conduct response exercises on a frequent basis.

Operator's Response Capability – Atlantic Canada

- Operators typically employ a three-tiered response capability with respect to equipment, reflected as Tier 1 - company owned and on site, Tier 2 – contracted, locally situated on shore, and Tier 3 – internationally situated. This provides for immediate response capability and scalable access to more equipment as needed. This includes equipment owned by Eastern Canada Response Corporation (ECRC) and the Canadian Coast Guard.
- The ECRC is an oil spill response contractor to the offshore industry in Canada. It is certified by Transport Canada under the Canada Shipping Act.

Operator's Response Capability – Northern Canada

- There is currently no industry spill response equipment in the Arctic offshore as there is no activity.
- Industry would put in place a spill response plan with Tiers similar to the East Coast example as part of their application for activity authorization – these plans would be "fit for purpose" reflecting Arctic conditions such as geography and local infrastructure.
- Operators would be required to have their spill response capability in place to receive approval to drill or produce.

Regulatory Requirements of Offshore Activity

- The process of preparation and prevention is highly regulated. Off the east coast, industry activity is governed by the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB), and the Canada-Nova Scotia Offshore Petroleum Board (C-NSOPB). These Boards report to Ministries of Natural Resources at both a provincial and federal level.
- Industry activity in the North falls under the auspice of the National Energy Board (NEB).
- Every offshore operator must have authorization from the requisite Board to pursue offshore activity under the *Canada Oil and Gas Operations Act (COGOA)*.
- Authorization submissions from operators must include a Safety Plan, an Environmental Protection Plan and a Contingency Plan as required by the *Canada Oil and Gas Drilling and Production Regulations*.
- All three plans provide extensive details on how a company will meet expectations with respect to equipment, personnel and processes in the areas of safety, environmental protection and contingencies
- All plans must meet the regulations of the federal and provincial governments and the guidelines of the offshore petroleum boards. Plans are approved prior to activity occurring.
- The application for authorization must also include:
    - in the case of a drilling installation, a description of the drilling and well control equipment and in the case of a production installation, a description of the processing facilities and control system;
- Regulators stipulate in their guidance notes to industry that they should have at least one of three emergency systems in place to get regulatory approval to proceed with operations, many operators use more than one system:
    1. Remote Vehicle System: (a remote vehicle is manoeuvred down to shut in the well manually).
    2. Acoustic System: (a signal is sent from the rig down to a blow-out prevention system which shuts in the well).
    3. Automatic Failsafe Mechanism: (there is a default position on the pipes and valves that is closed and it takes power to keep them open. When power is lost or shut down by the operator, they automatically shut in).

- Drilling a relief well is also an option and can be pursued in the event of a blow-out. Another rig is brought in and drills a well that intersects with the uncontrolled well. The oil or gas is then forced to flow up the relief well to the functioning rig. It can take up to several months to drill a relief well, depending on conditions.

- Offshore Petroleum Boards in Newfoundland and Nova Scotia do quarterly inspections of the operators, to ensure equipment is in place, meets regulations and is functional. Additionally, all regulated equipment has to be tested on a regular basis by operators and testing reported to the Boards. Equipment must be functional in real-time conditions.

- Northern operators are additionally required to follow the Same Season Relief Well Capability Policy. This policy was established in 1976 and requires operators to demonstrate the capability to drill a relief well within the same operating season, as determined by the NEB. A same season relief well involves the same techniques and processes as a typical relief well. Although the NEB had initiated a policy review, the SSRW Policy remains in effect.

Regulatory Adequacy

- The industry has been operating in Canada's offshore since the late 1960s. During this time hundreds of wells have been drilled with very few incidents. There have been two blowouts since offshore drilling began in Atlantic Canada (both in the 1980s).
- One can take from this that there is an effective regulatory regime and sound operating practices by industry in place to manage the inherent risks associated with this business.
- However, it does not mean that we should be complacent. As such, CAPP supports this Study and we would also point out that industry regulations are reviewed regularly by regulators to ensure alignment with public policy and technological advances.
- In recent years, regulatory regimes around the world related to the offshore oil and gas industry have been moving from a more prescriptive model to a goal-oriented model. Canada is also moving to a goal-oriented approach.
- Goal oriented regulation does not decrease standards or weaken regulation.
- Goal oriented regulation puts a higher onus on operators to be accountable for the decisions they make. Compliance under a goal oriented regime is not about simply following prescriptive requirements, but requiring the operators to design their operations to be the most effective and fit for purpose, allowing for both innovation and incorporation of new practices.
- Regulators remain accountable for ensuring the goals are met.

Concluding remarks

- Risk management is a fundamental premise of public policy – evident everywhere from rail and air travel to our roads system. It is not unique to oil and gas.
- The current regulatory system is designed to minimize and manage risk in a way that is deemed to be sufficiently protective and recoverable such that Canada's offshore resource can be developed.
- Industry accepts that this Study and other regulatory reviews that occur from time to time may identify opportunities to improve regulatory requirements.
- We would encourage a balanced approach, drawing on learnings from the Gulf incident, to any changes contemplated that provide for an appropriate level of protection while still enabling development of the important offshore resource.

Review of Offshore Oil-spill Prevention and Remediation Requirements and Practices in Newfoundland and Labrador

December 2010

Appendix XIII

David Pryce Presentation to Standing Senate Committee on Energy, the Environment and Natural Resources (Prepared by CAPP and presented on June 22, 2010)

Presentation to Standing Senate Committee on Energy, the Environment and Natural Resources
June 22, 2010

- Thank-you for the invitation to present today
- CAPP supports the objectives of these proceedings – we understand that it is the intent to better understand what is currently happening in Canada – the activity and what oversight is in place. It is important to reassure Canadians that these resources are being developed responsibly and that the risks associated are reduced as much as possible and that they are well managed, which includes being prepared to deal with an incident should it occur.
- CAPP and its members believe that the incident in the Gulf of Mexico is a tragic event, both from a human and an environmental perspective. It is in the interest of all stakeholders that we collectively take time to consider the findings and recommendations arising from the investigation of this incident.
- There is limited offshore activity in Canada currently – none in the Arctic and off the West Coast – which allows us time to assess the implications of what is occurring in the Gulf of Mexico and how we can best respond.

Who We Are

- CAPP represents more than 100 companies that produce about 90% of Canada's natural gas and crude oil as part of a $110 billion a year national industry.

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- As a Canadian Association we are able to provide broad industry views on policy and regulation, as well as information on the state of the industry. We are not able to comment on the circumstances of the Gulf of Mexico incident or the U.S. regulatory regime. Nor are we able to speak to specific company plans.

Set the Context

- Before getting into the specifics of my presentation, I wanted to note the context this Committee set for these hearings during its press conference, and specifically the importance the committee drew to the need to balance the 3 Es relationship – that being "the supply of oil and demand for energy, and environmental and economic considerations".
- We support the Committee's view of the 3 Es, and as we discuss today and going forward the risks associated with offshore drilling and how they can be managed, we believe a balance of the Es is important, and that the risks taken are considered within the context of economic and social opportunities, be they jobs, payments to governments to support delivery of services or building of infrastructure, or direct investments in the communities in which we operate.
- To put these opportunities in context:
    - The offshore oil and gas industry creates jobs, opportunities for local businesses and spending on research and development, education, training, and infrastructure. The people of a province or territory also benefit significantly from the royalties and taxes the industry pays to governments; these revenues support social and other programs
    - Specific jurisdictional benefits are highlighted as follows:

In Newfoundland and Labrador:

- Approximately $2.2 billion in oil royalties were paid to NL in the 2008-09 fiscal year and the oil and gas industry contributed approximately 28 % of provincial government revenues
- $16 billion in capital has been spent by the oil and gas industry in NL since 1995
- Over 3,000 people are directly employed by the industry. Thousands more work in the supply and service sector.

In Nova Scotia:

- The provincial government received over $1.5 billion in royalty-related revenues from years 1996 to 2008.
- From 1996 to 2007, total employment (direct and indirect) has been approximately 38,500 person-years, or an average employment of about 3,200 per year (full-time equivalent).
- Offshore royalties support social programs, infrastructure development, education and training; R&D; and debt reduction, among other things.

The North:

- In the North, we must speak of the potential benefits given that there is currently no activity in the offshore.
- The oil and gas industry can make a significant contribution to the federal Northern Strategy, by providing skills training and jobs and contributing to the social and economic well-being of communities, and thereby contributing to Canadian sovereignty in the North.
- Further, the indirect benefits in all offshore regions extend beyond these numbers, as the technology, skills and infrastructure created to support oil and gas industry spurs activity and growth in other areas.

Global Perspective

- The activity that provides these benefits takes place against a global backdrop
- The International Energy Agency projects world energy demand to grow by 40% over the next 20 years
- We believe all forms of energy will be necessary to meet this increase in demand. However, oil and gas will continue to be an important part of the energy mix going forward
- Oil and natural gas is expected to meet 40% of that growth in demand, as well as continuing to meet the base level demand at an even higher percentage.
- Global offshore crude oil production represents a significant part of the energy mix - providing 38% of the world's energy supply. Canadian offshore crude oil production represents about 10% of Canada's crude production.
- The offshore produces 2.5% of Canada's natural gas
- All forms of energy development pose environmental and safety risks. The challenge for government policy, regulators and industry collectively is to balance those risks in the 3 E context, and then take reasonable measures to mitigate the risks such that incidents are unlikely to occur, and to be prepared to respond to any such incident.

Regulatory Adequacy

- You have heard at this point from Canadian regulators who have explained the details of the Canadian system, and I would only reiterate for you that Canada has a robust regulatory system in place
- It provides multiple layers of oversight, ranging from the technical analysis of the well design and drilling processes, to the environmental impacts associated with the activity and contingency planning for how to address incidents should all else fail. In essence, it provides for a two-pronged approach: prevention and response capability.

- This regulatory regime has not been static, but has improved over time as it is reviewed regularly to ensure alignment with public policy and technological advances.
- In recent years, one of the more significant moves in regulatory regimes around the world, including in Norway and the UK, related to the offshore oil and gas industry has been a shift from a more prescriptive model to a performance or goal-oriented model. Canada has also been moving to a goal-oriented approach.
- There are a number of styles of regulating, which can be characterized as lying on a spectrum with prescriptive lying on one end and goal-oriented on the other.
- Goal oriented regulation, as the NEB discusses it, lies somewhere on that spectrum by being a mixture of performance based standards and prescriptive elements
- By way of example, the requirements in the Drilling and Production Regulations place the performance based requirement on operators to ensure that adequate procedures, materials and equipment are in place to minimize the risk of loss of well control. This is supplemented by the prescriptive requirement that two independent well barriers must be in place during all well operations. The prescriptive requirement does not allow any discretion on the part of the operator to only utilize one well barrier.
- Where the regulatory system eventually lands on the spectrum depends on a host of factors, including the regulators' familiarity with the industry and industry operations, the complexity of the industry and rate of innovation, as well as consideration of the risk involved in a given activity.
- However, the spectrum is not analogous to level of oversight - goal oriented regulation does not decrease standards or weaken regulation - it is based on the premise that it is the best means to encourage technological innovation while ensuring standards of safety and protection of the environment are met.

- Goal oriented regulation places operators in the position of higher accountability for the decisions they make. Compliance under a goal oriented regime is not about simply following prescriptive requirements or a checklist of what to do, but requiring the operators to assess the unique circumstances of their operations and design their operations to be the most effective and fit for purpose, allowing for both innovation and incorporation of new practices.
- Regulators remain accountable for ensuring the goals are met and will exercise that accountability through the oversight provided for in the activity approval process.
- However, to say that because our system has been effective so far is not to say that we should be complacent.
- Regulations, and where they sit on the regulatory system spectrum, are an evolutionary process that must adapt over time.
- Already, we have seen regulators in Canada responding to the events in the Gulf. The NEB has initiated their review of Safety and Environmental Drilling Requirements, and the CNLOPB is implementing new oversight measures for the East Coast well being drilled.
- CAPP supports the NEB review as a means of ensuring lessons learned from the Gulf are incorporated into Canadian practice, and we accept the increased vigilance by the CNOLPB as necessary until we learn more from the Gulf.

Division of Functions of the Boards

- Having described the system broadly, I'd like to take a few moments to address a few of the statements that have been put forward around the functions of the regulator both in Canada in the U.S.
- First off, I would make the observation that there exists right now a separation of functions between the industry promotion and financial benefits role of governments (housed with the federal and

provincial governments) and the technical regulatory functions provided by the offshore Boards.

- This situation avoids the potential conflict of interest that could exist otherwise and means that we already have in place a separation that has been an early recommendation in the U.S.
- Further, in presentations by other groups to the House of Commons Standing Committee on Natural Resources and in the media, there has been mention of the possibility of splitting the functions of the offshore petroleum boards in Atlantic Canada into two separate entities – one dealing with Environment Health and Safety and one dealing with licensing and other Board functions.
- While we understand those perspectives, we would also like this Committee to understand the value of an holistic approach to regulating. As the regulatory system in Atlantic Canada currently stands, safety and environment are paramount values under the regulatory framework. Safety and environment are considered in all aspects of the regulatory process, and to ensure that safety remains the top priority the position of the chief safety officer was created to give autonomy to an individual, which the Boards cannot override, focused specifically on safety.
- Safety in the regulatory context of the offshore petroleum boards includes protection of workers as well as protection of the environment, vessels, installations and equipment associated with offshore operations.
- Separating the Boards' responsibilities would be counter-productive to ensuring holistic oversight of the industry, and could potentially lead to inconsistent or conflicting direction to industry.
- Safety and operations are two sides of the same coin in that good equipment and operating practices are integral to safety

Risk Management, Safety, Prevention and Spill Response

Risk Management

- Industry approaches all activity with a goal to complete the activity without incident or injury and to minimize impacts on the environment. Risk is assessed and mitigative measures are applied to achieve a risk level that is as low as is reasonably practicable without eliminating the possibility of conducting an activity. Companies propose these risk management strategies as part of their application which is then subject to the judgment of acceptability by the regulator.

Safety

- Safety is the top priority for the offshore oil and gas industry and it is considered in all aspects of our activity.
- Companies put their rigs through rigorous safety inspections during planning, design and construction.
- Each rig must meet the safety standards of Transport Canada and the appropriate federal-provincial regulatory body.
- Offshore drilling rigs must also meet International rules and get inspected by Classification Societies like Lloyds of London to ensure proper design and capability.
- Companies have also developed their own safe operating practices based on years of experience operating in remote, harsh environments.

Prevention

- Operators work diligently to ensure that they have reduced any risk of an incident as much as possible in order to protect our people and the environment.
- This philosophy begins with engineering/process controls and well design, and continues through drilling practices, and is supported by specific technologies such as a blowout preventer.

- Examples of process controls put in place to minimize the likelihood of a spill include:
  - Comprehensive health, safety and environmental management systems that identify potential risk and ensure controls are in place to prevent spills
  - Operational procedures and techniques that incorporate the industry's best practices
  - Detailed preventative and corrective maintenance routines to ensure equipment remains fit for its intended purpose
  - Extensive training and competency assessment of personnel
  - Comprehensive internal and external review, inspection, testing and audit programs of facilities and processes.
  - Extensive monitoring of drilling and production operations by electronic systems and trained personnel to can identify potential issues before they occur.

Spill Response

- While the primary goal is prevention, operators are required to prepare for what could happen if all else fails.
- Companies must demonstrate capability to respond to any incident. In the case of an oil spill, companies approach their response with a view first to containment and ultimately recovery and clean-up.
- Response capability means ensuring access to necessary equipment and personnel.
- International best practice is for response plans to be structured in three Tiers, effectively scaling up from local to regional to international response capability as required by the situation. These scaled capabilities would be identified for review and approval within a project application. Additionally, companies are able to augment their immediate capability through mutual aid agreements.
- It also means ensuring an effective management system, typically referred to as an Incident Command System, which integrates companies and regulatory agencies to provide and define

leadership responsibilities and execution throughout the duration of an incident.

- Training is a key component of competent response capability, and companies are required to conduct response exercises on a frequent basis.
- Planning for these response measures would be reviewed as part of the Operator's application to the regulator before activity is approved and initiated.
- The determination of adequacy rests with the regulators, and industry's plans must always be to their satisfaction.

Concluding remarks

- The industry has been operating in Canada's offshore since the late 1960s. During this time hundreds of wells have been drilled with very few incidents.
- Technology and research are always advancing. Industry, along with governments, invests millions of dollars into R&D, not only on prevention but also on spill response. Both government and industry will draw from this research to identify gaps and to inform suitable prevention and response strategies.
- We have a modern regulatory regime in Canada that allows us to incorporate these new technologies and research into operations.
- However, it does not mean that we should be complacent, and the events in the Gulf are a painful reminder that we must always be vigilant and examine the risks we are taking and what can be done to mitigate them.
- This risk management is a fundamental premise of public policy – evident everywhere from rail and air travel to our roads system and health care strategies. It is not unique to oil and gas.
- This is where we must return to the Committee's notion of the 3 Es – Energy security, environment and the economy.
- We recognize that finding a balance in the risks we accept to advance the 3 Es is difficult.

- Industry begins this process by asking ourselves “can we do this safely”, and we design our operations with our own checks and balances so that the risks are mitigated.
- Ultimately however, the determination of whether that residual risk is acceptable is a matter of public policy, and it must be government and the regulator who make that determination in the public interest.
- We must all work together to ensure the regulatory system is designed to mitigate and manage risk in a way that is deemed to be sufficiently protective and recoverable such that Canada can continue to benefit from the developments of its offshore resources.

Review of Offshore Oil-spill Prevention and Remediation Requirements and Practices in Newfoundland and Labrador

December 2010

Appendix XIV

U.S. Congressional Subcommittee on Oversight and Investigations letter to Tony Hayward, Chief Executive Officer of BP (Dated June 14, 2010)

ONE HUNDRED ELEVENTH CONGRESS

Congress of the United States

House of Representatives

COMMITTEE ON ENERGY AND COMMERCE

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June 14, 2010

Mr. Tony Hayward
Chief Executive Officer
BP PLC
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United Kingdom

Dear Mr. Hayward:

We are looking forward to your testimony before the Subcommittee on Oversight and Investigations on Thursday, June 17, 2010, about the causes of the blowout of the Macondo well and the ongoing oil spill disaster in the Gulf of Mexico. As you prepare for this testimony, we want to share with you some of the results of the Committee's investigation and advise you of issues you should be prepared to address.

The Committee's investigation is raising serious questions about the decisions made by BP in the days and hours before the explosion on the Deepwater Horizon. On April 15, five days before the explosion, BP's drilling engineer called Macondo a "nightmare well." In spite of the well's difficulties, BP appears to have made multiple decisions for economic reasons that increased the danger of a catastrophic well failure. In several instances, these decisions appear to violate industry guidelines and were made despite warnings from BP's own personnel and its contractors. In effect, it appears that BP repeatedly chose risky procedures in order to reduce costs and save time and made minimal efforts to contain the added risk.

At the time of the blowout, the Macondo well was significantly behind schedule. This appears to have created pressure to take shortcuts to speed finishing the well. In particular, the Committee is focusing on five crucial decisions made by BP: (1) the decision to use a well design with few barriers to gas flow; (2) the failure to use a sufficient number of "centralizers" to prevent channeling during the cement process; (3) the failure to run a cement bond log to evaluate the effectiveness of the cement job; (4) the failure to circulate potentially gas-bearing drilling muds out of the well; and (5) the failure to secure the wellhead with a lockdown sleeve before allowing pressure on the seal from below. The common feature of these five decisions is that they posed a trade-off between cost and well safety.

Well Design. On April 19, one day before the blowout, BP installed the final section of steel tubing in the well. BP had a choice of two primary options: it could lower a full string of "casing" from the top of the wellhead to the bottom of the well, or it could hang a "liner" from the lower end of the casing already in the well and install a "tieback" on top of the liner. The liner-tieback option would have taken extra time and was more expensive, but it would have been safer because it provided more barriers to the flow of gas up the annular space surrounding these steel tubes. A BP plan review prepared in mid-April recommended against the full string of casing because it would create "an open annulus to the wellhead" and make the seal assembly at the wellhead the "only barrier" to gas flow if the cement job failed. Despite this and other warnings, BP chose the more risky casing option, apparently because the liner option would have cost $7 to $10 million more and taken longer.

Centralizers. When the final string of casing was installed, one key challenge was making sure the casing ran down the center of the wellbore. As the American Petroleum Institute's recommended practices explain, if the casing is not centered, "it is difficult, if not impossible, to displace mud effectively from the narrow side of the annulus," resulting in a failed cement job. Halliburton, the contractor hired by BP to cement the well, warned BP that the well could have a "SEVERE gas flow problem" if BP lowered the final string of casing with only six centralizers instead of the 21 recommended by Halliburton. BP rejected Halliburton's advice to use additional centralizers. In an e-mail on April 16, a BP official involved in the decision explained: "it will take 10 hours to install them. ... I do not like this." Later that day, another official recognized the risks of proceeding with insufficient centralizers but commented: "who cares, it's done, end of story, will probably be fine."

Cement Bond Log. BP's mid-April plan review predicted cement failure, stating "Cement simulations indicate it is unlikely to be a successful cement job due to formation breakdown." Despite this warning and Halliburton's prediction of severe gas flow problems, BP did not run a 9- to 12-hour procedure called a cement bond log to assess the integrity of the cement seal. BP had a crew from Schlumberger on the rig on the morning of April 20 for the purpose of running a cement bond log, but they departed after BP told them their services were not needed. An independent expert consulted by the Committee called this decision "horribly negligent."

Mud Circulation. In exploratory operations like the Macondo well, wells are generally filled with weighted mud during the drilling process. The American Petroleum Institute (API) recommends that oil companies fully circulate the drilling mud in the well from the bottom to the top before commencing the cementing process. Circulating the mud in the Macondo well could have taken as long as 12 hours, but it would have allowed workers on the rig to test the mud for gas influxes, to safely remove any pockets of gas, and to eliminate debris and condition the mud so as to prevent contamination of the cement. BP decided to forego this safety step and conduct only a partial circulation of the drilling mud before the cement job.

Lockdown Sleeve. Because BP elected to use just a single string of casing, the Macondo well had just two barriers to gas flow up the annular space around the final string of casing: the cement at the bottom of the well and the seal at the wellhead on the sea floor. The decision to use insufficient centralizers created a significant risk that the cement job would channel and fail, while the decision not to run a cement bond log denied BP the opportunity to assess the status of the cement job. These decisions would appear to make it crucial to ensure the integrity of the seal assembly that was the remaining barrier against an influx of hydrocarbons. Yet, BP did not deploy the casing hanger lockdown sleeve that would have prevented the seal from being blown out from below.

These five questionable decisions by BP are described in more detail below. We ask that you come prepared on Thursday to address the concerns that these decisions raise about BP's actions.

Background

BP started drilling the Macondo well on October 7, 2009, using the Marianas rig. This rig was damaged in Hurricane Ida on November 9, 2009. As a result, BP and the rig operator, Transocean, replaced the Marianas rig with the Deepwater Horizon. Drilling with the Deepwater Horizon started on February 6, 2010.

The Deepwater Horizon rig was expensive. Transocean charged BP approximately \$500,000 per day to lease the rig, plus contractors' fees.[1] BP targeted drilling the well to take 51 days and cost approximately \$96 million.[2]

The Deepwater Horizon was supposed to be drilling at a new location as early as March 8, 2010.[3] In fact, the Macondo well took considerably longer than planned to complete. By April 20, 2010, the day of the blowout, the rig was 43 days late for its next drilling location, which may have cost BP as much as \$21 million in leasing fees alone. It also may have set the context for the series of decisions that BP made in the days and hours before the blowout.

[1] According to the terms of the contract, the daily rate would range from \$458,000 in March 2008 to \$517,000 in September 2010. *See* Transocean, *Transocean Fleet Update*, fn. 11 (Apr. 13, 2010) (online at http://www.deepwater.com/fw/main/Fleet-Update-Report-58.html).

[2] BP, *GOM Exploration Wells MC 252 #1 – Macondo Prospect Well Information* (Sept. 2009) (BP-HZN-CEC008714).

[3] Testimony of Steve Tink, BP, Health, Safety and Environmental Manager, before the U.S. Coast Guard/MMS Marine Board of Investigation (May 26, 2010).

Well Design

Deepwater wells are drilled in sections. The basic process involves drilling through rock, installing and cementing casing to secure the wellbore, and then drilling deeper and repeating the process. On April 9, 2010, BP finished drilling the last section of the well. The final section of the wellbore extended to a depth of 18,360 feet below sea level, which was 1,192 feet below the casing that had previously been inserted into the well.[4]

At this point, BP had to make an important well design decision: how to secure the final 1,192 feet of the well. On June 3, Halliburton's Vice President of Cementing, Tommy Roth, briefed Committee staff about the two primary options available to BP. One option involved hanging a steel tube called a "liner" from a liner hanger on the bottom of the casing already in the well and then inserting another steel liner tube called a "tieback" on top of the liner hanger. The other option involved running a single string of steel casing from the seafloor all the way to the bottom of the well. Mr. Roth informed the Committee that "Liner/Tieback Casing provides advantage over full string casing with redundant barriers to annular flow."[5] In the case of a single string of casing, there are just two barriers to the flow of gas up the annular space that surrounds the casing: the cement at the bottom of the well and the seal at the wellhead. Mr. Roth told the Committee that in contrast, "Liner/Tieback provides four barriers to annular flow."[6] They are (1) the cement at the bottom of the well, (2) the hanger seal that attaches the liner to the existing casing in the well, (3) the cement that secures the tieback on top of the liner, and (4) the seal at the wellhead. The liner-tieback option also takes more time to install, requiring several additional days to complete.

Internal BP documents indicate that BP was aware of the risks of the single casing approach. An undated "Forward Plan Review" that appears to be from mid-April recommended against the single string of casing because of the risks. According to this document, "Long string of casing ... *was* the primary option" but a "Liner ... is now the recommended option."[7]

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[4] BP, PowerPoint Presentation, *Washington Briefing, Deepwater Horizon Interim Incident Investigation* at 4 (May 24, 2010).

[5] Briefing by Tommy Roth, Vice President of Cementing, Halliburton, to House Committee on Energy and Commerce Staff (June 3, 2010); Halliburton, PowerPoint Presentation, *Energy and Commerce Committee Staff Briefing* at 12 (June 3, 2010).

[6] *Id.* at 6.

[7] BP, *MC 252#1 Macondo, TD Forward Plan Review – Production Casing & TA Options*, at 9. (Apr. 2010) (BP-HZN-CEC-22109). The documents provided to the Committee from BP contain three versions of this document. This one and a second nearly identical version (BP, *MC 252#1 Macondo, TD Forward Plan Review – Production Casing & TA Options* (Apr. 2010)) (BP-HZN-CEC-22025) recommend against a single string casing and in favor of a liner

The document gave four reasons against using a single string of casing. They were:

- "Cement simulations indicate it is unlikely to be a successful cement job due to formation breakdown."
- "Unable to fulfill MMS regulations of 500' of cement above top HC zone."
- "Open annulus to the wellhead, with ... seal assembly as only barrier."
- "Potential need to verify with bond log, and perform remedial cement job(s)."[8]

In contrast, according to the document, there were four advantages to the liner option:

- "Less issue with landing it shallow (we can also ream it down)."
- "Liner hanger acts as second barrier for HC in annulus."
- "Primary cement job has slightly higher chance for successful cement lift."
- "Remedial cement job, if required, easier to justify to be left for later." [9]

Communications between employees of BP confirm they were evaluating these approaches. On April 14, Brian Morel, a BP Drilling Engineer, e-mailed a colleague, Richard Miller, about the options. His e-mail notes: "this has been [a] nightmare well which has everyone all over the place."[10]

Despite the risks, BP chose to install the single string of casing instead of a liner and tieback, applying for an amended permit on April 15.[11] The company's application stated that the full casing string would start at 9 7/8 inches diameter at the top of the well and narrow to 7 inches diameter at the bottom.[12] This application was approved on the same day.[13]

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approach. The third version recommends in favor of the single string of casing and is discussed below.

[8] *Id.* "HC" stands for hydrocarbon.

[9] *Id.* at 10.

[10] E-mail from Brian Morel, Drilling Engineer, BP, to Richard Miller, BP (Apr. 15, 2010) (BP-HZN-CEC-21857).

[11] BP, *Form MMS 123A/123S – Electronic Version, Application for Revised Bypass* (Apr. 15, 2010) (BP-HZN-CEC018357).

[12] *Id.*

[13] E-mail from Frank Patton, MMS, to Heather Powell, JC Connor Consulting ("Modification of Permit to Bypass as Location Surface Lease: G32306 Surface Area: MC Surface Block: 252 Bottom Lease: G32306 Bottom Area: MC Bottom Block: 252 Well Name: 001 Assigned API Number: 608174116901 has been approved. as of 2010-04-15 14:39:39.0") (Apr. 14, 2010). Ms. Powell then forwarded the approval to BP. E-mail from Heather Powell,

The decision to run a single string of casing appears to have been made to save time and reduce costs. On March 25, Mr. Morel e-mailed Allison Crane, the Materials Management Coordinator for BP's Gulf of Mexico Deepwater Exploration Unit, that the long casing string "saves a lot of time … at least 3 days."[14] On March 30, he e-mailed Sarah Dobbs, the BP Completions Engineer, and Mark Hafle, another BP Drilling Engineer, that "[n]ot running the tieback … saves a good deal of time/money."[15] On April 15, BP estimated that using a liner instead of the single string of casing "will add an additional $7 - $10 MM to the completion cost."[16] The same document calls the single string of casing the "[b]est economic case and well integrity case for future completion operations."[17]

Around this time, BP prepared another undated version of its "Forward Plan Review." Notably, this version of the document reaches a different conclusion than the other version, calling the long string of casing "the primary option" and the liner "the contingency option."[18] Like the other version of the plan review, this version acknowledges the risks of a single string of casing, but it now describes the option as the "Best economic case and well integrity case for future completion operations."[19]

Centralizers

Centralizers are attachments that go around the casing as it being lowered into the well to keep the casing in the center of the borehole. If the well is not properly centered prior to the cementing process, there is increased risk that channels will form in the cement that allow gas to flow up the annular space around the casing. API Recommended Practice 65 explains: "If casing is not centralized, it may lay near or against the borehole wall. … It is difficult, if not

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JC Connor Consulting, to Mark Hafle, Senior Drilling Engineer, BP (Apr. 15, 2010) (BP-HZN-CEC021033).

14 E-mail from Brian Morel, Drilling Engineer, BP, to Allison Crane, Materials Management Coordinator, BP Gulf of Mexico Deepwater Exploration (Mar. 25, 2010). (BP-HZN-CEC021880).

15 E-mail from Brian Morel, Drilling Engineer, BP, to Sarah Dobbs, Completions Engineer, BP, and Mark Hafle, Senior Drilling Engineer, BP (Mar. 30, 2010) (BP-HP-CEC021948).

16 BP, *Drilling & Completions MOC Initiate* (Apr. 15, 2010) (BP-HZN-CEC021656).

17 *Id.*

18 BP, *TD Forward Plan Review, Production Casing & TA Options* at 6-7 (undated) (BP-HZN-CEC-022145).

19 *Id.*

impossible, to displace mud effectively from the narrow side of the annulus if casing is poorly centralized. This results in bypassed mud channels and inability to achieve zonal isolation."[20]

On April 15, BP informed Halliburton's Account Representative, Jesse Gagliano, that BP was planning to use six centralizers on the final casing string at the Macondo well. Mr. Gagliano spent that day running a computer analysis of a number of cement design scenarios to determine how many centralizers would be necessary to prevent channeling.[21] With ten centralizers, the modeling resulted in a "MODERATE" gas flow problem.[22] Mr. Gagliano's modeling showed that it would require 21 centralizers to achieve only a "MINOR" gas flow problem.[23]

Mr. Gagliano informed BP of these results and recommended the use of 21 centralizers.[24] After running a model with ten centralizers, Mr. Gagliano e-mailed Brian Morel, BP's drilling engineer, and other BP officials, stating that the model "now shows the cement channeling" and that "I'm going to run a few scenarios to see if adding more centralizers will help us or not."[25] Twenty-five minutes later, Mr. Morel e-mailed back:

> We have 6 centralizers, we can run them in a row, spread out, or any combination of the two. It's a vertical hole, so hopefully the pipe stays centralized due to gravity. As far as changes, it's too late to get any more product on the rig, our only option[] is to rearrange placement of these centralizers.[26]

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[20] API, Recommended Practice 65-Part 2, *Isolating Potential Flow Zones During Well Construction*, 4.6.5.8., at 28.

[21] House Committee on Energy and Commerce, Transcribed Interview of Jesse Marc Gagliano, at 26 (June 11, 2010).

[22] Halliburton, *9 7/8" X 7" Production Casing Design Report* (Apr. 15, 2010) (HAL_0010592).

[23] Halliburton, *9 7/8" X 7" Production Casing Design Report* (Apr. 15, 2010) (HAL_0010699).

[24] House Committee on Energy and Commerce, Transcribed Interview of Jesse Marc Gagliano, at 8 (June 11, 2010).

[25] E-mail from Jesse Gagliano, Account Representative, Halliburton, to Mark Hafle, Senior Drilling Engineer, BP, Brian Morel, Drilling Engineer, BP, Brett Cocales, Operations Drilling Engineer, BP, and Gregory Walz, Drilling Team Leader, BP (Apr. 15, 2010) (HAL_0010650).

[26] E-mail from Brian Morel, Drilling Engineer, BP, to Jesse Gagliano, Account Representative, Halliburton, Mark Hafle, Senior Drilling Engineer, BP, Brett Cocales, Operations Drilling Engineer, BP, and Gregory Walz, Drilling Team Leader, BP (Apr. 15, 2010) (HAL_0010648).

The following day, April 16, the issue was elevated to John Guide, BP's Well Team Leader, by Gregory Walz, BP's Drilling Engineering Team Leader. Mr. Walz informed Mr. Guide: "We have located 15 Weatherford centralizers with stop collars … in Houston and worked things out with the rig to be able to fly them out in the morning." The decision was made because "we need to honor the modeling to be consistent with our previous decisions to go with the long string."[27] Mr. Walz explained: "I wanted to make sure that we did not have a repeat of the last Atlantis job with questionable centralizers going into the hole."[28] Mr. Walz added: "I do not like or want to disrupt your operations. … I know the planning has been lagging behind the operations and I have to turn that around."[29]

In his response, Mr. Guide raised objections to the use of the additional centralizers, writing: "it will take 10 hrs to install them. … I do not like this and … I [am] very concerned about using them."[30]

An e-mail from Brett Cocales, BP's Operations Drilling Engineer, indicates that Mr. Guide's perspective prevailed. On April 16, he e-mailed Mr. Morel:

> Even if the hole is perfectly straight, a straight piece of pipe even in tension will not seek the perfect center of the hole unless it has something to centralize it.
>
> But, who cares, it's done, end of story, will probably be fine and we'll get a good cement job. I would rather have to squeeze than get stuck. … So Guide is right on the risk/reward equation.[31]

On April 17, Mr. Gagliano, the Halliburton account representative, was informed that BP had decided to use only six centralizers.[32] He then ran a model using seven centralizers and

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[27] E-mail from Gregory Walz, Drilling Team Leader, BP, to John Guide, Well Team Leader, BP (Apr. 16, 2010) (BP-HZN-CEC0022433).

[28] *Id.*

[29] *Id.*

[30] *Id.*

[31] E-mail from Brett Cocales, Operations Drilling Engineer, BP, to Brian Morel, Drilling Engineer, BP (Apr. 16, 2010) (BP-HZN-CEC022670).

[32] House Committee on Energy and Commerce, Transcribed Interview of Jesse Marc Gagliano, at 40-41 (June 11, 2010).

found this would likely produce channeling and a failure of the cement job.[33] His April 18 cementing design report states: "well is considered to have a SEVERE gas flow problem."[34] Mr. Gagliano said that BP was aware of the risks and proceeded with knowledge that his report indicated the well would have a severe gas flow problem.[35]

Mr. Gagliano's findings should not have been a surprise to BP. As noted above, BP's mid-April plan review found that if BP used a single string of casing, as BP had decided to do, "Cement simulations indicate it is unlikely to be a successful cement job."[36] Nonetheless, BP ran the last casing with only six centralizers.[37]

Cement Bond Log

A cement bond log is an acoustic test that is conducted by running a tool inside the casing after the cementing is completed. The cement bond log determines whether the cement has bonded to the casing and surrounding formations. If a channel that would allow gas flow is found, the casing can be perforated and additional cement injected into the annular space to repair the cement job.

Mr. Roth, the Halliburton Vice President of Cementing, informed the Committee staff that BP should have conducted a cement bond log. According to Mr. Roth, "If the cement is to be relied upon as an effective barrier, the well owner must perform a cement evaluation as part of a comprehensive systems integrity test."[38]

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[33] *Id.* at 8. Mr. Gagliano told the Committee that at the time he ran a model with seven centralizers, he knew of BP's decision to use only six. He told the Committee that running a model with seven centralizers demonstrated that the difference between six and seven centralizers would be unlikely to affect the outcome of the modeling.

[34] Halliburton, *9 7/8" X 7" Production Casing Design Report* (Apr. 18, 2010) (HAL_0010955).

[35] House Committee on Energy and Commerce, Transcribed Interview of Jesse Marc Gagliano, at 43-45 (June 11, 2010).

[36] BP, *MC 252#1 Macondo, TD Forward Plan Review – Production Casing & TA Options*, at 9. (Apr. 2010) (BP-HZN-CEC-22109).

[37] BP, *Daily Operations Report – Partners (Completion)* (Apr. 18, 2010) (HAL_0028210).

[38] Briefing by Tommy Roth, Vice President of Cementing, Halliburton, to House Committee on Energy and Commerce Staff (June 3, 2010); Halliburton, PowerPoint Presentation, *Energy and Commerce Committee Staff Briefing* at 12 (June 3, 2010).

Minerals Management Service (MMS) regulations also appear to direct a cement bond log or equivalent test at the Macondo well. According to the regulations, if there is an indication of an inadequate cement job, the oil company must "(1) Pressure test the casing shoe; (2) Run a temperature survey; (3) Run a cement bond log; or (4) Use a combination of these techniques."[39] In the case of the Macondo well, the Halliburton and internal BP warnings should have served as an indication of a potentially inadequate cement job.

On April 18, BP flew a crew from Schlumberger to the rig. As described in a Schlumberger timeline, "BP contracted with Schlumberger to be available to perform a cement bond log … should BP request those services."[40] But at about 7:00 a.m. on the morning of April 20, BP told the Schlumberger crew that their services would not be required for a cement bond log test.[41] As a result, the Schlumberger crew departed the Deepwater Horizon at approximately 11:15 a.m. on a regularly scheduled BP helicopter flight.[42] The Schlumberger crew was scheduled for departure before pressure testing of the well had been completed, indicating that the results of those tests were not a factor in BP's decision to send the crew away without conducting a cement bond log.[43]

BP's decision not to conduct the cement bond log test may have been driven by concerns about expense and time. The cement bond log would have cost the company over $128,000 to complete.[44] In comparison, the cost of canceling the service was just $10,000.[45] Moreover, Mr. Roth of Halliburton estimated that conducting the test would have taken an additional 9 to 12 hours.[46] Remediating any problems found with the cementing job would have taken still more time.[47]

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[39] 30 CFR § 250.428.

[40] Schlumberger, *Mississippi Canyon Block 252 Timeline* (undated) (SLB-EC-000002).

[41] *Id.*

[42] *Id.*

[43] Briefing by Mark Bly, Group Vice President for Safety & Operations, BP, to House Committee on Energy and Commerce Staff (May 25, 2010).

[44] Schlumberger, *Estimated Costs of Equipment/Labor to Perform the Contingent Services Identified by BP and the Actual Costs Upon Cancellation* (SLB-EC-000909).

[45] *Id.*

[46] Briefing by Tommy Roth, Vice President of Cementing, Halliburton, to House Committee on Energy and Commerce Staff (June 3, 2010).

[47] A BP document indicates that the company would rely on lost mud "returns" during the cementing process as a trigger for conducting a cement bond log. BP, *GOM Exploration Wells MC 252 #1ST00BP01- Macondo Prospect 7" x 9-7/8" Interval* at 3 (Apr. 15, 2010) (BP-

The Committee staff asked an independent engineer with expertise in the analysis of well failure about BP's decision not to conduct a cement bond log. The engineer, Gordon Aaker, Jr., P.E., a Failure Analysis Consultant with the firm Engineering Services, LLP, said that it was "unheard of" not to perform a cement bond log on a well using a single casing approach, and he described BP's decision not to conduct a cement bond log as "horribly negligent."[48] Another independent expert consulted by the Committee, John Martinez, P.E., told the committee that "cement bond or cement evaluation logs should always be used on the production string."[49]

Mud Circulation

Another questionable decision by BP appears to have been the failure to circulate fully the drilling mud in the well before cementing. This procedure, known as "bottoms up," involves circulating drilling mud from the bottom of the well all the way to the surface. Bottoms up has several purposes: it allows workers on the rig to test the mud for influxes of gas; it permits a controlled release of gas pockets that may have entered the mud; and it ensures the removal of well cuttings and other debris from the bottom of the well, preventing contamination of the cement.

API's guidelines recommend a full bottoms up circulation between running the casing and beginning a cementing job. The recommended practice states that "when the casing is on bottom and before cementing, circulating the drilling fluid will break its gel strength, decrease its viscosity and increase its mobility. The drilling fluid should be conditioned until equilibrium is achieved. … At a minimum, the hole should be conditioned for cementing by circulating 1.5 annular volumes or one casing volume, whichever is greater."[50]

HZN-CEC017621). Mr. Gagliano of Halliburton told the Committee that lost returns are not a reliable indicator of channeling: "the amount of returns would not tell you if there's channeling or not. Full returns just indicates the amount of fluid you're pumping into the wellbore, you're getting the equal or very close to equal volume back at surface, which is telling you that you're not fracturing any fluids into the formation or losing any fluids. It's not really an indication of channeling." House Committee on Energy and Commerce, Transcribed Interview of Jesse Marc Gagliano, at 86 (June 11, 2010).

[48] Briefing by Gordon Aaker, Jr., P.E., Failure Analysis Consultant with Engineering Services, L.P. (Houston), to House Committee on Energy and Commerce Staff (June 10, 2010).

[49] E-mail from John Martinez, P.E., an independent production specialist on wellbore construction, to House Committee on Energy and Commerce Staff (June 10, 2010).

[50] API, Recommended Practice 65-Part 2, *Isolating Potential Flow Zones During Well Construction*, 4.8.4., at 36-37.

BP's April 15 operations plan called for a full bottoms up procedure to "circulate at least one (1) casing and drill pipe capacity, if hole conditions allow."[51] Halliburton Account Representative Jesse Gagliano said it was also "Halliburton's recommendation and best practice to at least circulate one bottoms up on the well before doing a cement job."[52] According to Mr. Gagliano, a Halliburton engineer on the rig raised the bottoms up issue with BP.[53]

Despite the BP operations plan and the Halliburton recommendation, BP did not fully circulate the mud. Instead, it chose a procedure "written on the rig" which Mr. Gagliano "did not get input in."[54] BP's final procedure called for circulating just 261 barrels of mud, just a small fraction of the mud in the Macondo well.[55] Mr. Roth of Halliburton told the Committee that one reason for the decision not to circulate the mud could have been a desire for speed, as fully circulating the mud could have added as much as 12 hours to the operation.[56] Mr. Gagliano expressed a similar view, saying, "the well probably would not have handled too high of a rate. So it would take a little bit … longer than usual to circulate bottoms up in this case."[57]

Lockdown Sleeve

A final question relates to BP's decision not to install a critical apparatus to lock the wellhead and the casing in the seal assembly at the seafloor. When the casing is placed in the wellhead and cemented in place, it is held in place by gravity. Under certain pressure conditions, however, the casing can become buoyant, rising up in the wellhead and potentially creating an opportunity for hydrocarbons to break through the wellhead seal and enter the riser to the surface. To prevent this, a casing hanger lockdown sleeve is installed.

On June 8, 2010, Transocean briefed Committee staff on its investigation into the potential causes of the explosion on board the Deepwater Horizon. In the presentation, Transocean listed the lack of a lockdown sleeve as one of its "areas of investigation." Slide

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[51] BP, *GOM Exploration Wells, MC252 #1ST00PBP01 – Macondo Prospect 7" X 9 7/8" Interval, Rev. H.2* at 6 (Apr. 15, 2010) (BP-HZN-CEC-017621).

[52] House Committee on Energy and Commerce, Transcribed Interview of Jesse Marc Gagliano, at 57 (June 11, 2010).

[53] *Id.* at 61.

[54] *Id.* at 57.

[55] *Id.* at 60.

[56] Briefing by Tommy Roth, Vice President of Cementing, Halliburton, to House Committee on Energy and Commerce Staff (June 3, 2010).

[57] House Committee on Energy and Commerce, Transcribed Interview of Jesse Marc Gagliano, at 65-66 (June 11, 2010).

seven of Transocean's presentation asks: "Were Operator procedures appropriate?" A subpoint details: "Operator did not run lock down sleeve prior to negative test or displacement."[58] Mr. Roth of Halliburton raised a similar concern in his June 3 briefing for Committee staff.[59]

In BP's planned procedure for the well, BP describes two options involving the lockdown sleeve. BP was seeking permission from MMS to install the final cement plug on the well at a lower depth than previously approved. If permission was granted, BP's plan was to displace the drilling mud in the riser with seawater and install the cement plug prior to installation of the casing hanger lockdown sleeve. BP's alternative plan, if MMS did not approve the proposed depth of the final cement plug, was to run the lockdown sleeve first, before installing the cement plug at a shallower depth.[60] On April 16, Brian Morel, BP's drilling engineer, e-mailed BP staff that: "We are still waiting for approval of the departure to set our surface plug. … If we do not get this approved, the displacement/plug will be completed shallower after running the LDS."[61] The LDS stands for the lockdown sleeve.

Conclusion

The Committee's investigation into the causes of the blowout and explosion on the Deepwater Horizon rig is continuing. As our investigation proceeds, our understanding of what happened and the mistakes that were made will undoubtedly evolve and change. At this point in the investigation, however, the evidence before the Committee calls into question multiple decisions made by BP. Time after time, it appears that BP made decisions that increased the risk of a blowout to save the company time or expense. If this is what happened, BP's carelessness and complacency have inflicted a heavy toll on the Gulf, its inhabitants, and the workers on the rig.

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[58] Transocean, PowerPoint Presentation, *Deepwater Horizon Incident – Internal Investigation: Investigation Update – Interim Report* at 7 (June 8, 2010).

[59] Briefing by Tommy Roth, Vice President of Cementing, Halliburton, to House Committee on Energy and Commerce Staff (June 3, 2010).

[60] BP, *GOM Exploration Wells MC 252 #1ST00BP01- Macondo Prospect 7" x 9-7/8" Interval* at 8 (Apr. 15, 2010) (BP-HZN-CEC017621).

[61] E-mail from Brian Morel, Drilling Engineer, BP, to Ronald Sepulvado et al. (Apr. 16, 2010) (BP-HZN-CEC022821).

During your testimony before the Committee, you will be asked about the issues raised in this letter. This will provide you an opportunity to respond to these concerns and clarify the record. We appreciate your willingness to appear and your cooperation in the Committee's investigation.

Sincerely,

Henry A. Waxman

Henry A. Waxman
Chairman

Bart Stupak

Bart Stupak
Chairman
Subcommittee on Oversight and Investigations

Enclosure

cc: The Honorable Joe Barton
Ranking Member

The Honorable Michael C. Burgess
Ranking Member
Subcommittee on Oversight and Investigations

Review of Offshore Oil-spill Prevention and Remediation Requirements and Practices in Newfoundland and Labrador

December 2010

Appendix XV

Spill Related Properties of Newfoundland and Labrador

Crude Oils

Appendix XV – Spill Related Properties of Newfoundland and Labrador Crude Oils

1.0 Introduction and Background

Crude oil is a mixture of thousands of chemical compounds. Each crude contains different amounts of these compounds and thus is unique in composition and in the way that it weathers when spilled on the sea. The properties of a crude oil can change over the time period that an individual well is produced, and production crude oils are usually a blend of crude from several wells. The properties of a production crude can change based on the proportions of the crudes from each well that make up the sales crude. Also, during production operations, small amounts of chemicals may be injected into the crude to improve its flow properties or reduce its produced water content.

When crude oil is spilled in the marine environment its physical and chemical properties will change over time through processes such as evaporation and emulsification. These changes will affect not only the fate, behavior, and effects of the spill, but also the opportunities for using countermeasures effectively. For example, a crude oil may be relatively fluid and non-viscous when initially spilled, but may become viscous within a short time. It is important to know whether this will happen and how long it will take, defining the so-called "Window of Opportunity" for countermeasures. For instance, dispersants are most effective on low- to medium-viscosity oils, and in-situ burning is not possible once stable emulsions have formed.

Crude oils from exploration and production operations offshore Newfoundland and Labrador have been analyzed to determine their spill-related properties for over 25 years (samples of Hibernia and Avalon crudes were first analyzed in 1982). To date, 22 different samples have been analyzed from the Hibernia (including Avalon), Terra Nova, Hebron, and White Rose fields. This section discusses which physical oil properties are important to determining how spilled oil will behave, and presents the key properties of crudes from offshore Newfoundland and Labrador.

2.0 Important Spill-related Physical Properties of Crude Oils

Spill-related analyses of the physical properties of crude oils generally focus on determining the rate at which the oil loses light ends when exposed to the atmosphere (evaporation) and the rate at which the oil takes up and retains seawater droplets (emulsification) as a result of wave action. These analyses typically focus on the first few hours and days after a crude oil has been spilled and the effects of these weathering processes on the following key physical properties of the oil:

- Density,
- Viscosity, and
- Pour Point

Other weathering processes, such as biodegradation, tar ball formation, and photo-oxidation, occur over longer time periods of days to weeks, and involve different types of chemical analyses, usually involving sophisticated gas chromatographic and mass spectrometer measurements to detect changes in individual components of the crude oil. It is the physical properties and their changes when spilled that are the focus of this section.

2.1 Evaporation

A variety of techniques are used to artificially evaporate crude oil samples to obtain estimates of how quickly a given crude would evaporate if spilled at sea under specific environmental conditions (e.g., temperature, wind speed, and slick thickness) and to produce samples for physical property analysis of the weathered crude. These techniques include evaporation of pre-weighed samples in a wind tunnel, bubbling air through a sample, heating the sample in a rotary evaporator to a specified end point and distilling the oil until a specified point is reached. Most of these techniques can be mathematically inter-related and correlated with environmental and oil-slick conditions at sea.

2.2 Density

Density, the mass per unit volume of the oil (or emulsion), determines how buoyant a crude oil is in water. The common unit of density is grams per millilitre (g/mL). The density of crude oil increases with weathering and decreases with increasing temperature. Density affects the following processes:

- Sinking - if the density of the oil exceeds that of the water (1.025 g/mL for full-salinity seawater) it will sink. As the density approaches that of seawater and the buoyancy of smaller oil forms (such as emulsion mats or tar balls) decreases, wave action can temporarily submerge these oil forms beneath the surface and keep them there until the waves subside - this makes detection and cleanup of the oil difficult;

- Spreading - in the early stages of a spill, more dense oils spread faster;
- Natural Dispersion - more dense oils naturally disperse into the water column as tiny droplets more easily; and,
- Emulsification - dense oils tend to form more stable emulsions.

2.3 Viscosity

Viscosity is a measure of the resistance of oil to flowing, once it is in motion. The common unit of viscosity is the centi-Poise (cP); the SI unit is the milli-Pascal second (mPas), which is numerically equivalent to the centi-Poise. The viscosity of oil increases as weathering progresses and decreases with increasing temperature. Viscosity is one of the most important properties from the perspective of spill behavior and affects the following processes:

- Spreading - viscous oils spread more slowly;
- Natural and Chemical Dispersion - highly viscous oils are difficult to disperse;
- Emulsification Tendency and Stability - viscous oils form more stable emulsions, up to a point - extremely viscous oils do not emulsify; and,
- Recovery and Transfer Operations - more viscous oils are generally harder to skim and more difficult to pump.

2.4 Pour Point

The pour point is the lowest temperature (to the nearest multiple of 3°C) at which a crude oil will still flow in a small test jar tipped on its side. Near, and below this temperature, the oil develops a yield stress and, in essence, gels. The pour point of an oil increases with weathering. Pour point affects the following processes:

- Spreading - oils at temperatures below their pour points will not spread on water;
- Viscosity - oil's viscosity at low shear rates (i.e., the rate at which the oil is mixed) increases dramatically at temperatures below its pour point;
- Dispersion - oil at a temperature well below its pour point may be difficult to disperse; and,

- Recovery, Transfer, and Storage - oil below its pour point may not flow toward skimmers or down inclined surfaces in skimmers, and at temperatures well below the pour point may present storage/transfer challenges.

2.5 Emulsification Tendency and Stability

The tendency of crude oil to form water-in-oil emulsions (or “mousse”) and the stability of the emulsion formed are measured in a test that involves tumbling oil and seawater in a glass cylinder for defined periods of time, then stopping the tumbling and measuring how long it takes for the oil and water to separate (if ever). Recently the emulsification assessment has been changed to reflect the four categories suggested by Environment Canada. Emulsion types are selected based on water content, emulsion viscosity and/or the visual appearance of the emulsion after repeated tumbling and settling for three hours, followed by 24 hours of settling. The four categories, and their defining characteristics, are:

1) Unstable - looks like original oil; water contents after 24 hours of 1% to 23% averaging 5%; viscosity same as oil on average

2) Entrained Water - looks black, with large water droplets; water contents after 24 hours of 26% to 62% averaging 42%; emulsion viscosity 13 times greater than oil on average

3) Meso-stable - brown viscous liquid; water contents after 24 hours of 35% to 83% averaging 62%; emulsion viscosity 45 times greater than oil on average

4) Stable - the classic “mousse”, a brown gel/solid; water contents after 24 hours of 65% to 93% averaging 80%; emulsion viscosity 1100 times greater than oil on average

The tendency of an oil to emulsify and the stability of the emulsion formed both generally increase with increased degree of evaporation. Colder temperatures generally increase both the tendency and stability (i.e., promote emulsification). One way of characterizing emulsification is to use the lab test results to define the degree of evaporation of the crude oil at which it will form Stable or Meso-stable emulsions at a given temperature (the degree of evaporation is called the Emulsification Delay). (This method is commonly used in many state-of-the-art computer models to predict oil-spill behaviour at sea.) Once the necessary degree of evaporation is reached, the emulsification algorithm commences and the emulsion water content increases as a function of sea state and the emulsion viscosity increases as a function of the water content, parent oil viscosity and other variables.

Emulsion formation leads to three significant and negative results:

- Large increases in the spill's volume, with commensurate increases in volumes to be skimmed, stored, transferred, and disposed of;
- Enormous increases in viscosity, which can reduce skimmer and chemical dispersant effectiveness; and
- Increases in water content, which can prevent ignition of the slicks and in-situ burning.

3.0 Data on Newfoundland and Labrador Offshore Crudes

Figure 1 shows the density (at 15°C) of the various fresh (i.e., unevaporated) crude oil samples from offshore Newfoundland and Labrador plotted against the year of their sampling and analysis. Samples from the same areas (Hibernia, including the Avalon crude, which now is a component of the sales crude from Hibernia, Terra Nova, White Rose, and Hebron) are grouped on the graph by being encircled by a coloured line. Most of the crudes fall into the density range termed "medium gravity" and would be expected to float on seawater even if heavily evaporated. The Hebron crudes are denser and approach the lower range of "heavy" crudes. Even the Hebron crudes would be expected to float on normal seawater when heavily evaporated. Although there is some variation over time in the density of some of the samples from a given area, the density of the fresh crude from each area has remained relatively constant.

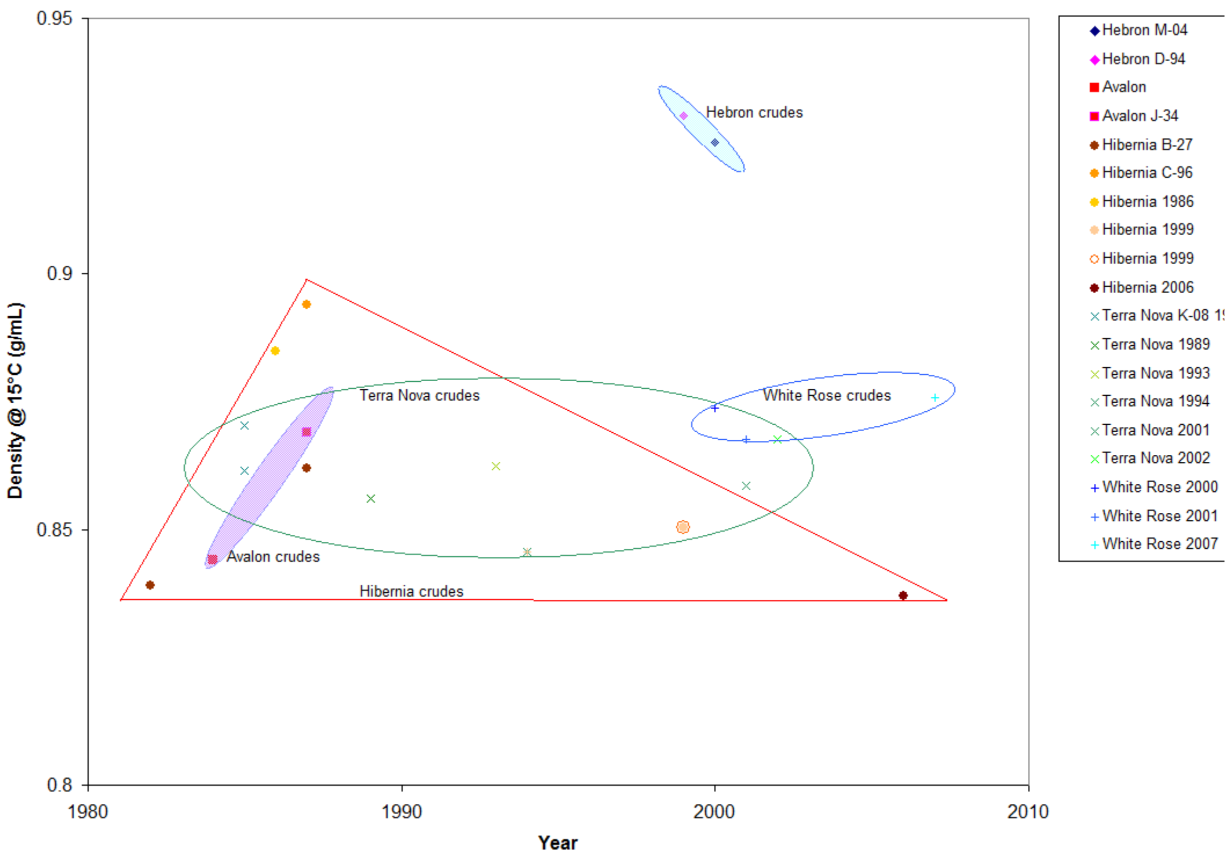

Figure 1 - Density of Offshore Crude Oil Samples from 1982 Onward

(Source: Environment Canada, 2010)

If any of these crudes were to become heavily emulsified with seawater, the density of the resulting emulsion could approach 1.01 g/mL and wave action could temporarily submerge smaller forms (i.e., droplets and mats) of the emulsion beneath the surface.

Figure 2 presents the viscosity (at 15°C) of the various crude samples as a function of time. Note that the y-axis is logarithmic and extends from 10 to 1 000 PMa's. The fresh Terra Nova and Hibernia crude samples tend to be less viscous when fresh than the White Rose and Hebron crude samples. Again, although there is some variation in the viscosity of the crudes from the same area, there do not appear to be any great changes in viscosity over time. The possible exception is for the White Rose crude, probably due to the samples' high pour points compared with the measurement temperature of 15°C.

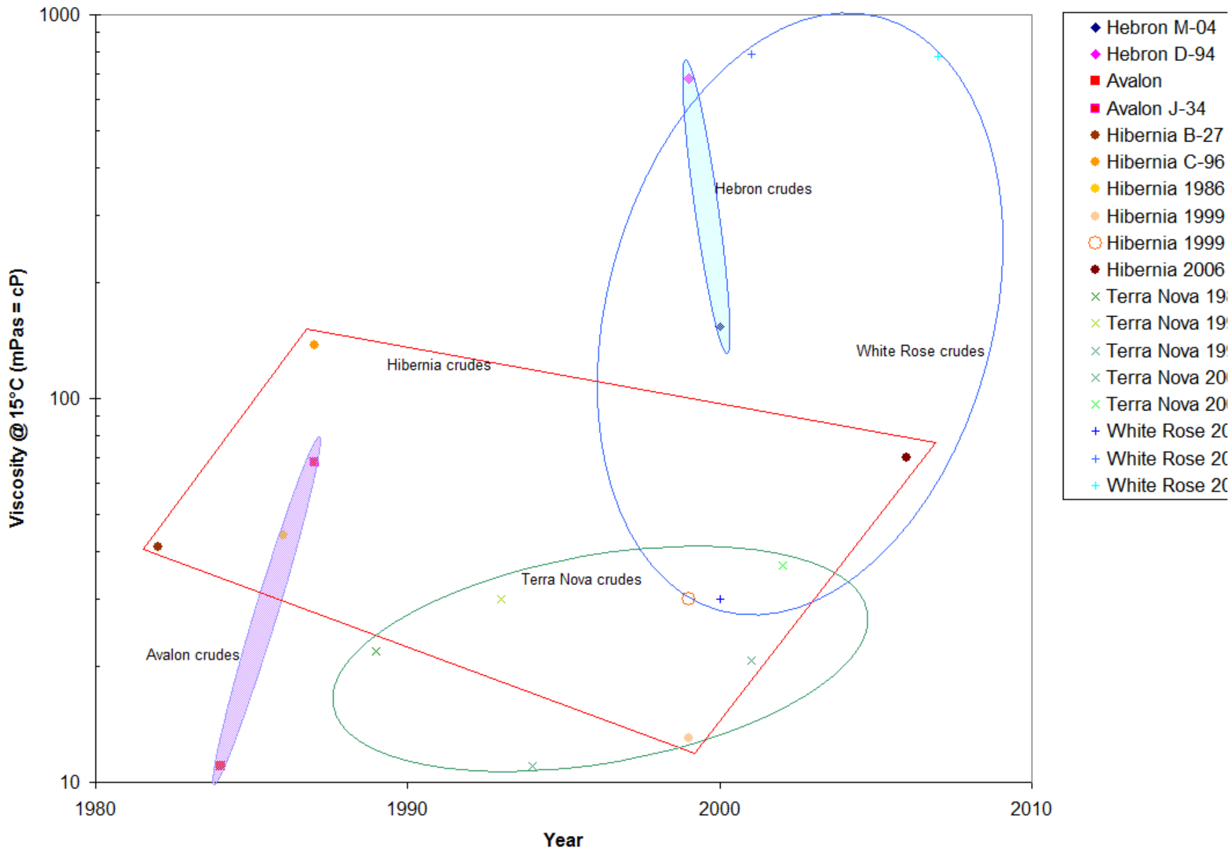

Figure 2 - Viscosity of Offshore Crude Oil Samples from 1982 Onward

(Source: Environment Canada, 2010)

Figure 3 illustrates the pour points of the fresh crude samples over the years. With the exception of the Hebron crudes and one Hibernia sample from 1999, the pour points of the crudes exceed 0°C, and in some cases 10°C. This means that even the fresh crude, if spilled offshore in winter, will begin to gel very quickly and become a semi-solid in a short time. Even in summer temperatures offshore, only a slight amount of evaporation will cause these crudes to begin to gel. This means that the oil slicks (perhaps better described as droplets or mats) will persist for considerable time periods and the gelled oil may resist chemical dispersion and be more challenging to skim and pump.

One aspect of the weathering of high pour point crudes is that, as they evaporate, the waxes contained in the crude that cause the high pour point, begin to form a waxy "skin" on the surface of the oil droplets and mats. This waxy "skin" significantly reduces the spilled oil's adhesion to oleophilic surfaces such as sorbents or feathers.

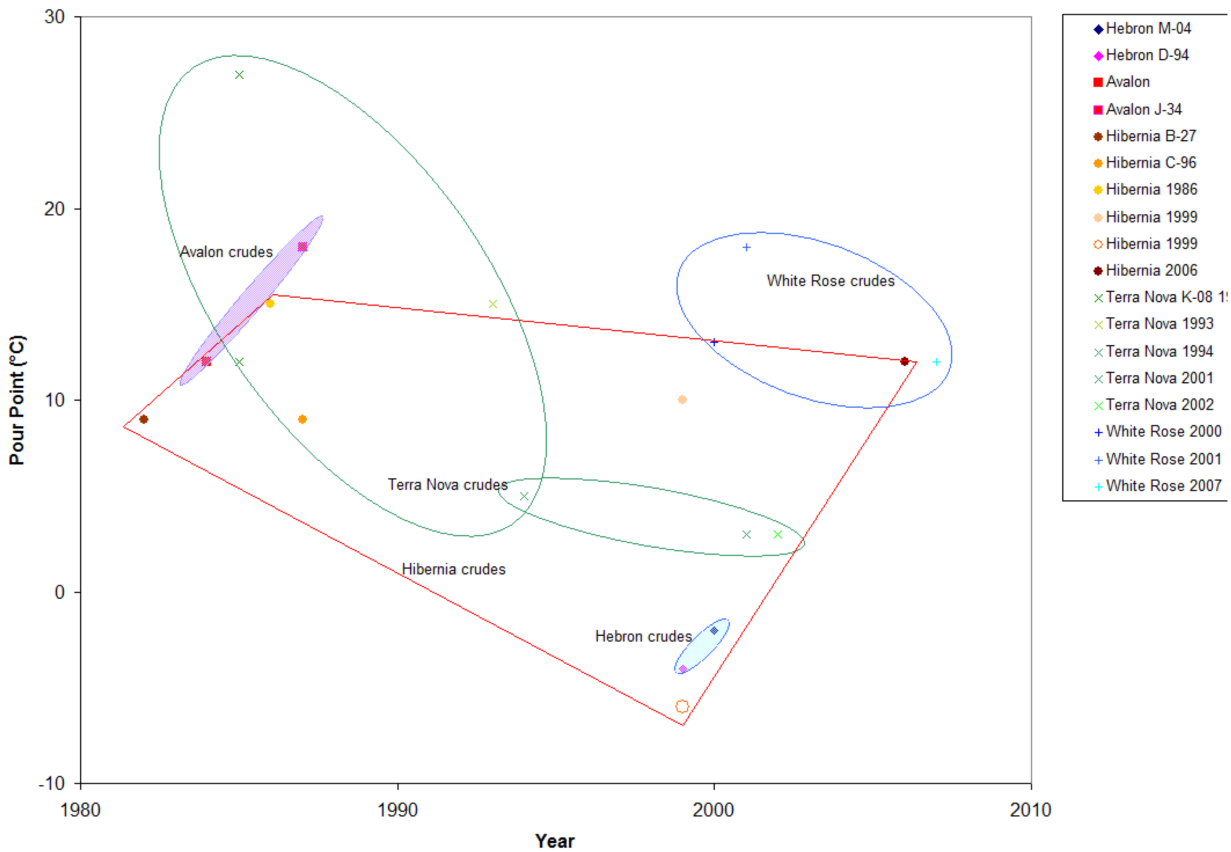

Figure 3 - Pour Point of Offshore Crude Oil Samples from 1982 Onward

(Source: Environment Canada, 2010)

Figure 4 shows the delay in the onset of emulsification for the crudes (note that not all the available oil property data sets included emulsification information) and the changes in the delay over the years. The delay is expressed as the percent loss to evaporation necessary for the crude oil to start to form a stable emulsion at 10° or 15°C (some data sets contained emulsification information at 10° and some at 15°C).

Generally speaking, the onset of emulsification will occur sooner in winter conditions. For many of the crudes, the required evaporation for the formation of stable emulsions is low, or zero, meaning that these crudes will begin to form emulsions shortly after being spilled. Note that, if the oil is spilled as a result of a blowout, it is possible that the oil will be in the form of small droplets of gelled oil on the water surface, which will not emulsify.

The recent Hibernia crude oil sample analyses seem to indicate a trend in increasing emulsification delay, with the latest sample analyzed in 2006 requiring nearly 30% loss to evaporation before stable emulsions will form. This provides a larger "Window of Opportunity" for chemical dispersants and in-situ burning.

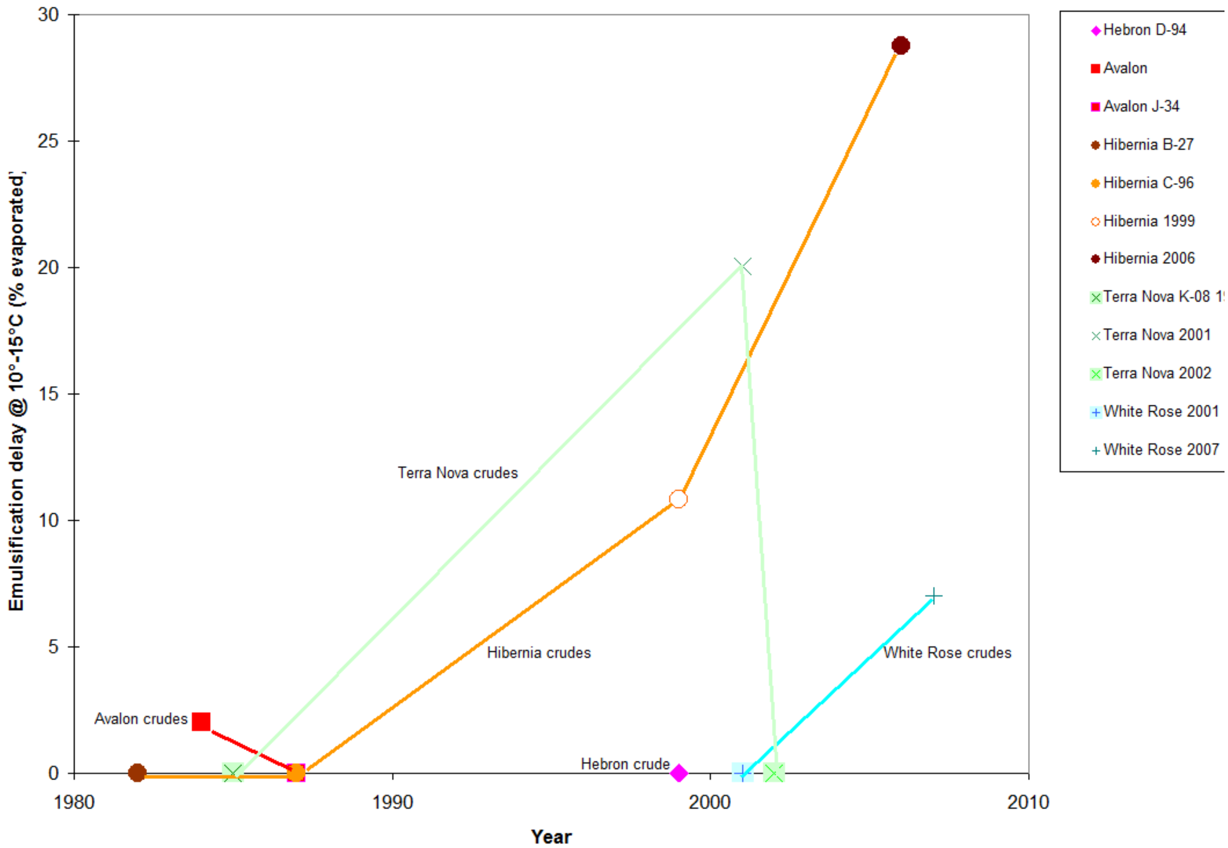

Figure 4 - Emulsification Delay for Offshore Crude Oil Samples from 1982 Onward

(Source: Environment Canada, 2010)

4.0 Summary of Newfoundland and Labrador Offshore Crude Oil Properties

The following summarizes the most significant oil properties with regards to oil-spill behaviour and countermeasures:

- There is nothing particularly unusual about most of the oils: for the most part they have medium density and viscosity.
- Most of the oils have pour points that are in excess of ambient temperatures in winter, and will have pour points in excess of summer temperatures after some weathering. This means that the oils will tend to gel and be difficult to skim, pump, or disperse. This will not affect their ability to be burned in-situ.
- Most of the oils will emulsify after some degree of weathering, but in most cases, there will be a significant delay, which will allow the use of skimming, burning, and/or dispersant use.
- Emulsification may lead to some of the oils becoming neutrally buoyant, which could cause the oil to submerge, but it should not sink.

Review of Offshore Oil-spill Prevention and Remediation Requirements and Practices in Newfoundland and Labrador

December 2010

Appendix XVI

Recommendations from the U.S. Department of the Interior

Report on Increased Safety Measures for Energy

Development on the Outer Continental Shelf (May 2010)

Table 1 - Summary of US Regulatory Recommendations

Main Area	Sub-Area		No.	Recommendations
I) BOP Equipment and Emergency Systems	A) Certification of Subsea BOP Stack		1	Order Immediate Re-certification of All BOP Equipment Used in New Floating Drilling Operations
			2	Order BOP Equipment Compatibility Verification for Each Floating Vessel and for Each New Well
			3	Develop Formal Equipment Certification Requirements
	B) New Safety Equipment Requirements and Operating Procedures		4	New Blind Shear Ram Redundancy Requirement
			5	Secondary Control System Requirements and Guidelines
			6	New ROV Operating Capabilities
	C) New Testing Guidelines and Inspection Procedures		7	Develop New Testing Requirements
			8	Develop New Inspection Procedures and Reporting Requirements
II) Procedures to Ensure Adequate Physical Barriers and Well Control Systems are in Place to Prevent Oil and Gas from Escaping into the Environment – Minimizing Risk of Uncontrolled Flow	A) Well-Control Guidelines and Fluid Displacement Procedures		9	Establish Deepwater Well-Control Procedure Guidelines
			10	New Fluid Displacement Procedures
	B) Well Design and Construction	1)Requirements for Both Casing and Cementing	11	New Casing and Cement Design Requirements: Two Independent Tested Barriers
			12	Study Formal Personnel Training Requirements for Casing and Cementing Operations
		2) Casing Requirements	13	New Casing Installation Procedures
			14	Develop Additional Requirements or Guidelines for Casing Installation
		3) Cementing Requirements	15	Enforce Tighter Primary Cementing Practices
			16	Develop Additional Requirements or Guidelines for Evaluation of Cement Integrity
	C) Wild-Well Intervention		17	Increase Federal Government Wild-Well Intervention Capabilities
			18	Study Innovative Wild-Well Intervention, Response Techniques, and Response Planning
III) Organizational and Safety Management	A) Increased Enforcement of Existing Safety Regulations and Procedures Enforcing Existing Regulations		19	Compliance Verification for Existing Regulations and April 30, 2010, National Safety Alert
	B) Organizational Management Organizational Safety Case Documentation		20	The Department Will Adopt Safety Case Requirements for Floating Drilling Operations on the OCS
	C) Personnel Accountability Procedures for Operational Safety (Risk, Injury, and Spill Prevention)		21	Finalize a Rule that Would Require Operators to Develop a Robust Safety and Environmental Management System for Offshore Drilling Operations
			22	Study Additional Safety Training and Certification Requirements

Main Area I: BOP Equipment and Emergency Systems

Sub-Area A: Certification of Subsea BOP Stack

Recommendation 1: Order Immediate Re-certification of All BOP Equipment Used in New Floating Drilling Operations

Prior to spudding any new well from a floating vessel, the operator will be required to obtain a written and signed certification from an independent third party attesting that, a detailed physical inspection and design review of the BOP has been conducted in accordance with the Original Equipment Manufacturer specifications and that: (i) the BOP will operate as originally designed, and (ii) any modifications or upgrades to the BOP stack conducted after delivery have not compromised the design or operation of the BOP. This certification must be submitted to the Department and made publicly available. Prior to the deployment of the BOP, the operator must also verify that any modifications or upgrades to the BOP are approved by the Department and that documentation showing that the BOP has been maintained and inspected according to the requirements in 30 CFR 250.44(a) and other applicable standards and is on file with the Department and available for inspection.

Recommendation 2 - Order BOP Equipment Compatibility Verification for Each Floating Vessel and for Each New Well

For each new well, the Department will require, as part of a structured risk management process, the operator to obtain independent third party verification that:

- The BOP stack is designed for the specific drilling equipment on the rig and for the specific well design including certification that the shear ram is appropriate for the drilling project.
- The BOP stack has not been compromised or damaged from previous service.
- The BOP stack will operate in the water depth in which it will be deployed.

Recommendation 3 - Develop Formal Equipment Certification Requirements

The Department will investigate new certification requirements for BOP equipment and other components of the BOP stack such as control panels, communication pods, accumulator systems, and choke and kill lines. In addition, the Department will develop a system to make BOP certifications publicly available in order to increase transparency and accountability.

Sub-Area B: New Safety Equipment Requirements and Operating Procedures

Recommendation 4 - New Blind Shear Ram Redundancy Requirement

The BOP used in all floating drilling operations will be required to have two sets of blind shear rams spaced at least four feet apart (to prevent system failure if drill pipe or drill tool is across one set of rams during an emergency).

Recommendation 5 - Secondary Control System Requirements and Guidelines

The Department will establish clear requirements for secondary BOP control systems on all subsea BOP's and for systems that address well-control emergencies. These requirements will include:

- ROV intervention capabilities for secondary control of all subsea BOP stacks, including the ability to close all shear and pipe rams, close the choke and kill valves and unlatch the lower marine riser package (LMRP).

- Requirements for an emergency back-up BOP control system, such as autoshear, deadman, emergency disconnect system, and/or an acoustic activation system that is powered by a separate and independent accumulator bank with sufficient capacity to open and close one annular-type preventer and all ram-type preventers, including the blind shear ram.

- Guidelines for arming and disarming the secondary BOP control system.

- Requirements for documentation of BOP maintenance and repair (including any modifications to the BOP stack and control systems).

Recommendation 6 - New ROV Operating Capabilities

The Department will develop requirements for ROV operating capabilities including the following:

- Standardized intervention ports for all subsea BOP stacks to ensure compatibility with any available ROV.

- Visible mechanical indicator or redundant telemetry channel for BOP rams to give positive indication of proper functioning (e.g., a position indicator).

- ROV testing requirements, including subsea function testing with external hydraulic supply.

- An ROV interface with dual valves below the lowest ram on the BOP stack to allow well-killing operations.

Sub-Area C: New Testing Guidelines and Inspection Procedures

Recommendation 7 - Develop New Testing Requirements

The Department will develop surface and subsea testing of ROV and BOP stack capabilities. These will include:

- Surface and subsea function and pressure testing requirements to ensure full operability of all functions (emergency disconnect of the LMRP and loss of communication with the surface control pods (e.g., electric and hydraulic power).

- Third party verification that blind-shear rams will function and are capable of shearing the drill pipe that is in use on the rig.

- ROV performance standards, including surface and subsea function testing of ROV intervention ports and ROV pumps, to ensure that the ROV can close all shear and pipe rams, close the choke and kill valves, and unlatch the LMRP.

- Protocols for function testing autoshear, deadman, emergency disconnect systems, and acoustic activation systems.

- Mandatory inspection and testing of BOP stacks if any components are used in an emergency (e.g., use of pipe or casing shear rams or circulating out a well kick). This testing must involve a full pressure test of the BOP after the situation is fully controlled, with the BOP on the wellhead.

Recommendation 8 - Develop New Inspection Procedures and Reporting Requirements

- The Department will evaluate and revise the manner in which it conducts its drilling inspections. Revised drilling inspections will include the witnessing of actual tests of BOP equipment, including the new requirements and guidance that address the surface and subsea testing of ROV and BOP stack capabilities. The Department will also develop methods to increase transparency and public availability of the results of inspections as well as routine reporting. The Department will work with Congress to obtain the necessary resources to implement these recommendations.

- Within 15 days of the date of the MMS report, all operators of floating drilling equipment will report to the Department the following: (i) BOP and well control system configuration; (ii) BOP and well control system test results, including any anomalies in testing or operation of critical BOP components; (iii) BOP and loss of well control events; and (iv) BOP and well control system downtime for the last three years of drilling operations.

- The electronic log from the BOP control system must be transmitted online to a secure location onshore and made available for inspection by the Department.

Main Area II: Procedures to Ensure Adequate Physical Barriers and Well Control Systems are in Place to Prevent Oil and Gas from Escaping into the Environment - Minimizing Risk of Uncontrolled Flow

A well creates a conduit for subsurface formations to potentially flow uncontrolled to the surface. There are multiple methods that can be utilized to minimize the risk of the occurrence of uncontrolled flow. Those methods include the installation of rigid physical barriers such as cement plugs or mechanical plugs, well casing design and securing of the casing, and well control equipment. An appropriate well safety program must account for many factors unique to the drill location and dictates the installation of plugs and casing at strategic points to maintain well control and to enable drilling to the desired depth. Current Department regulations require that well-control equipment be in place at all times during the drilling operation to mitigate against failure of a plug or casing. Other, more specific standards may be appropriate to improve physical barriers and well-control systems. Well control procedures must be revisited for deepwater operations because of the complexity of the equipment design in deepwater and the location of the BOP stack on the seafloor. Enhanced training for rig personnel will complement new well-control requirements.

Sub-Area A: Well-Control Guidelines and Fluid Displacement Procedures

Recommendation 9 - Establish Deepwater Well-Control Procedure Guidelines

As expeditiously as possible, the Department will establish new requirements for deepwater well-control procedures no later than 120 days after the date of this report (MMS report).

Recommendation 10 - New Fluid Displacement Procedures

Prior to displacement of kill-weight drilling fluid from the wellbore, the operator must independently verify that:

- The BOP's are closed during displacement to underbalanced fluid columns to prevent gas entry into the riser should a seal failure occur during displacement.

- Two independent barriers, including one mechanical barrier, are in place for each flow path (i.e., casing and annulus), except that a single barrier is allowable between the top of the wellhead housing and the top of the BOP.

- If the shoe track (the cement plug and check valves that remain inside the bottom of casing after cementing) is to be used as one of these barriers, it is negatively pressure tested prior to the setting of the subsequent casing barrier. A negative pressure test must also be performed prior to setting the surface plug.

- Negative pressure tests are made to a differential pressure equal to or greater than the anticipated pressure after displacement. Each casing barrier is positively tested to a pressure that exceeds the highest estimated integrity of the casing shoes below the barrier.

- Displacement of the riser and casing to fluid columns that are underbalanced to the formation pressure in the wellbore is conducted in separate operations. In both cases, BOP's must be closed on the drill string and circulation established through the choke line to isolate the riser, which is not a rated barrier. During displacement, volumes in and out must be accurately monitored.

- Drill pipe components positioned in the shear rams during displacement must be capable of being sheared by the blind-shear rams in the BOP stack.

Sub-Area B-1: Well Design and Construction - Requirements for both Casing and Cementing

Recommendation 11 - New Casing and Cement Design Requirements: Two Independent Tested Barriers

Before spudding any new floating drilling operation, all well casing and cement designs must be certified by a Professional Engineer, who verifies that there will be at least two independent tested barriers, including one mechanical barrier, across each flow path during well completion and abandonment activities and that the casing design is appropriate for the purpose for which it is intended under reasonably expected wellbore conditions.

Recommendation 12 - Study Formal Personnel Training Requirements for Casing and Cementing Operations

The Department will immediately establish a technical workgroup to evaluate new training and certification requirements for rig personnel specifically related to casing and cementing operations.

Sub-Area B-2: Well Design and Construction - Casing Requirements

Recommendation 13 - New Casing Installation Procedures

The Department will ensure the requirement of the following the Best Available and Safest Technologies (BAST) practices:

- Casing hanger latching mechanisms or lock down mechanisms must be engaged at the time the casing is installed in the subsea wellhead.

- For the final casing string, the operator must verify the installation of dual mechanical barriers (e.g., dual floats or one float and a mechanical plug) in addition to cement, to prevent flow in the event of a failure in the cement.

Recommendation 14 - Develop Additional Requirements or Guidelines for Casing Installation

The Department will establish specific requirements for the following procedures and practices:

- Positive and negative test procedures and use of test results for evaluation of casing integrity.

- Use of float valves and other mechanical plugs in the final casing string or liner.

Sub-Area B-31: Well Design and Construction - Cementing Requirements

Recommendation 15 - Enforce Tighter Primary Cementing Practices

- The Department will institute a rulemaking to address previously identified gaps in primary cementing practices.

- The Department, with input from independent experts will determine specific cementing requirements.

Recommendation 16 - Develop Additional Requirements or Guidelines for Evaluation of Cement Integrity

The Department will immediately evaluate whether and under what circumstances the use of cement bond logs is feasible and practical and will increase safety.

Discussion of Recommendations 11 - 16

Recommendations 11 - 16 are intended to result in better well control. Requiring a Professional Engineer to review and certify the well design will add another level of review to the current well design requirements. The Department's review of new training requirements for casing and cementing operations helps focus industry and rig personnel on the importance of proper casing and cementing operations. Additional operational requirements for casing installation and cementing operations will add new assurances that adequate barriers are in place before continuing on to new drilling activities. Incorporation of the new cementing standard will bring all of industry up to state-of-the-art cementing practices – this means less chance of a well blowout due to a poor cement job.

Sub-Area C: Wild-Well Intervention

Recommendation 17 - Increase Federal Government Wild-Well Intervention Capabilities

Blown out, or "wild" wells, involve the uncontrolled release of crude oil or natural gas from an oil well where pressure control systems have failed. The Federal Government must develop a plan to increase its capabilities for direct wild-well intervention to be better prepared for future emergencies, particularly in deepwater. Development of the plan should consider existing methods to stop a blowout and handle escaping wellbore fluids, including but not limited to coffer dams, highly-capable ROVs, portable hydraulic line hook-ups, and pressure-reading tools, as well as appropriate sources of funding for such capabilities.

Recommendation 18 - Study Innovative Wild-Well Intervention, Response Techniques, and Response Planning

The Department will investigate new methods to stop a blowout and handle escaping wellbore fluids. A technical workgroup will take a fresh look at how to deal with a deepwater blowout. In particular, the workgroup will evaluate new, faster ways of stopping blowouts in deepwater. The technical workgroup will also address operators' responsibility, on a regional or industry-wide basis, to develop and procure a response package for deepwater events, to include diagnostic and measurement equipment, pre-fabricated systems for deepwater oil capture, logistical and communications support, and plans and concepts of operations that can be deployed in the event of an unanticipated blowout, as well as assess and certify potential options (e.g., deepwater dispersant injection).

Main Area III: Organizational and Safety Management

Sub-Area A: Increased Enforcement of Existing Safety Regulations and Procedures Enforcing Existing Regulation

Immediately following the BP Oil Spill, the MMS and the U.S. Coast Guard issued a joint Safety Alert to compel operators and drilling contractors to inspect their drilling equipment (both surface and subsea), review their procedures to ensure the safety of personnel and protection of the environment, and review all emergency shutdown and dynamic positioning procedures. Inspections began immediately to verify that all active deepwater drilling activities complied with these recommendations and all other regulations. Following the completion of the drilling inspections, inspections of all deepwater production facilities began immediately to ensure compliance by those facilities with the regulations. Reconfirmation of adherence to this Safety Alert and all existing regulations will heighten safety awareness.

Recommendation 19 - Compliance Verification for Existing Regulations and April 30, 2010, National Safety Alert

Within 30 days of the date of this report (MMS report), the Department, in conjunction with the Department of Homeland Security, verify compliance by operators with existing regulations and National Safety Alert (issued April 30, 2010), which issued the following safety recommendations to operators and drilling contractors:

- Examine all well-control equipment (both surface and subsea) currently being used to ensure that it has been properly maintained and is capable of shutting in the well during emergency operations. Ensure that the ROV hot-stabs are function-tested and are capable of actuating the BOP.

- Review all rig drilling/casing/completion practices to ensure that well-control contingencies are not compromised at any point while the BOP is installed on the wellhead.

- Review all emergency shutdown and dynamic positioning procedures that interface with emergency well control operations.

- Inspect lifesaving and firefighting equipment for compliance with Federal requirements.

- Ensure that all crew members are familiar with emergency/firefighting equipment, as well as participate in an abandon ship drill. Operators are reminded that the review of emergency equipment and drills must be conducted after each crew change out.

- Exercise emergency power equipment to ensure proper operation.

- Ensure that all personnel involved in well operations are properly trained and capable of performing their tasks under both normal drilling and emergency well-control operations.

After the 30-day compliance period, the Department will provide a public report on operator verification, including any cases of non-compliance.

Sub-Area B: Organizational Management Organizational Safety Case Documentation

A safety case is a comprehensive and structured set of safety documentation to ensure the safety of a specific vessel or equipment. This documentation is essentially a body of evidence that provides a basis for determining whether a system is adequately safe for a given application in a given environment. In response to the 1988 Piper Alpha disaster in the U.K., the Lord Cullen investigation and report advanced the safety case concept for offshore oil and gas operations.

The use of a formal safety case for drilling operations is an important component in regulating drilling activities in many countries. The International Association of Drilling Contractors (IADC) has developed guidelines that can be applied to any drilling unit regardless of geographic location. The use of these guidelines can assist both the operator and regulatory authorities when evaluating a drilling contractor's safety management program by providing them assurance that the program encompasses a series of best industry practices designed to minimize operating risks. The Department will undertake an evaluation of requiring the application of all or part of these guidelines to OCS oil and gas operations.

Recommendation 20 - The Department Will Adopt Safety Case Requirements for Floating Drilling Operations on the OCS

The Department will assure the adoption of appropriate safety case requirements based on IADC Health, Safety and Environmental Case Guidelines for Mobile Offshore Drilling Units (2009), which will include well construction safety assessment prior to approval of APD. This safety case must establish risk assessment and mitigation processes to manage a drilling contractor's controls related to the health, safety, and environmental aspects of their operations. In addition to the safety case, a separate bridging document will be required to connect the safety case to existing well design and construction documents. Such a proposed Well Construction Interfacing Document will include all of the elements in a conventional bridging document plus alignment of the drilling contractor's management of change (MOC) and risk assessment to the lease operator's MOC and well execution risk assessments. The use of the AIDC's Health, Safety, and Environmental Case Guidelines for Mobile Offshore Drilling Units will help operators and drilling contractors demonstrate their ability to operate safely and handle the risks associated with drilling on the OCS.

Sub-Area C: Personnel Accountability Procedures for Operational Safety (Risk, Injury, and Spill Prevention)

Recommendation 21 - Finalize a Rule that Would Require Operators to Develop a Robust Safety and Environmental Management System for Offshore Drilling Operations

Department investigation findings and reports indicate that unsafe offshore drilling operations often result from human error. The Department is proceeding with the rulemaking process to finalize a regulation to require operators on the OCS to adopt a comprehensive, systems-based approach to safety and environmental management that incorporates best practices from around the globe. The Department believes that requiring operators to implement robust and comprehensive safety and environmental management plans could reduce the risk and number of injuries and spills during OCS activities. The Department will finalize a rule that is informed by current operational conditions in the Gulf and the events and related investigation surrounding the BP Oil Spill.

Recommendation 22 - Study Additional Safety Training and Certification Requirements

The Department will immediately establish a workgroup to investigate safety training requirements for floating drilling rig personnel and possible requirements for independent or more frequent certification and testing of personnel and safety systems.

- Establish an oil production safety program or institute similar to U.S. Nuclear Regulatory Commission (NRC) reactor safety program.

- Establish a formalized analytical methodology to assess performance of safety systems in the event of multiple component failure or excursions outside normal environmental ranges.

- Strengthen technical support to the Department and other regulatory authorities including the resources necessary to obtain independent technical review of regulations and standards.

- Charter a longer-term technical review of BOP equipment and emergency backup system reliability.

- Review and adopt as appropriate best practices from other agencies with similar responsibility for safety regulation of technically complex systems (e.g., Federal Aviation Administration, NRC, Chemical Safety Board, and National Transportation Safety Board).

This review was conducted without the benefit of the findings from the ongoing investigation into the root causes of the explosions and fire on the Deepwater Horizon and the resulting oil spill including if there were any violations of existing safety or construction laws, gross negligence, or willful misconduct. In the coming months, those investigations will likely suggest refinements to some of the report's recommendations, as well as additional safety measures. Nevertheless, the information currently available points to a number of specific interim recommendations regarding equipment, systems, procedures, and practices needed for safe operation of offshore drilling activities.

In developing the recommendations the Department was guided by the principle that feasible measures that materially and undeniably reduce the risk of a loss-of-well-control event should be pursued. Therefore, some recommended measures – particularly those the Departments already implemented – are necessarily prescriptive. At the same time, the Department is examining innovative ways to promote a culture of safety for offshore operations by addressing the human element of operations. The Department is committed to finalizing a rulemaking that would require operators to adopt a system-based approach to safety and environmental management. This rule would require operators to incorporate global best practices regarding environmental and safety management on offshore platforms into their operating plans and procedures. In finalizing this rulemaking, the Department will analyze carefully the current circumstances in the Gulf of Mexico and lessons learned from the ongoing investigation into the causes of the BP Oil Spill.

Review of Offshore Oil-spill Prevention and Remediation Requirements and Practices in Newfoundland and Labrador

December 2010

Appendix XVII

Compensation Claim Form and Instructions (per the C-NLOPB and C-NSOPB)

Appendix XIII – Compensation Claim Form

Date:____________________________

1. **Name of Claimant:** ____

2. **Occupation:** ____

3. **Address & Telephone Numbers:** ____

   Home: ______________________________ **Business:** _______________________

   ______________________________ _______________________

   ______________________________ _______________________

   ______________________________ _______________________

4. **Relationship to property lost or damaged:** _______________________________________

5. **Location, date and approximate time of incident:** _________________________________

   ____

6. **Details of incident and damage sustained:** ***(attach details if required):*** ______________

   ____

   ____

   ____

7. **Damage or loss attributed to:** ____

   ____

   ____

8. **Supporting information:** ***(attach details if required):*** _____________________________

   ____

   ____

COMPENSATION CLAIM FORM

Page 2

9. Description of property lost or damaged: ***(attach details if required):*** **_____________**

____

____

____

10. Nature of income loss (if applicable):

____

____

____

____

11. Other Sources of Compensation: Yes: _____ No: _____

If yes:

Name of Source: ____

Amount Received: ____

12. Amount of Claim: ____

13. Date claim made to responsible offshore operator: _____________________________

14. Declaration:

I, __________________________________ Of ________________________________

in the Province of ________________________________ do solemnly declare that I

conscientiously believe that the information given above is true.

Date: ___________________

Signed: ___________________

Signature witnessed: ___________________

INSTRUCTIONS FOR COMPLETING THE COMPENSATION CLAIMFORM

The claim form is provided as a structure for registering a claim. Care must be taken to record and date all relevant information under the 14 headings. These may include:

1. **Name of claimant:** It should be stated whether the claim is for personal loss or whether the individual is filing a claim on behalf of others.

2. **Occupation:** Although a person's occupation may not have any relationship to the nature of the claim (e.g. automobile mechanic whose waterfront property was polluted), it should always be provided. In other instances the claimant may be a fisherman, a vessel owner, or hunter in which case the person's licence number should also be included.

3. **Address:** Sufficient information to contact the claimant at home or at work should be given.

4. **Relationship:** It should be stated whether the claimant owns, leases or operates the property lost or damaged.

5. **Location, etc.**: This is important for correlation with offshore petroleum activity. If the claim is for damage to a vessel or fishing gear the location may be given by latitude and longitude, or in relation to known geographical features.

6. **Details, etc.:**

   The following information should be included for pollution damage:

   - location of fouled shoreline where applicable;
   - description of gear or facilities damaged;
   - impact upon use of property;
   - required remedy;
   - reason for claimant having personal property in area where spill occurred.

   The following information should be included for debris-related damage information:

   - name of vessel, registration and home port;
   - manner of use or deployment at time of incident;
   - nature of damage or loss sustained;
   - effect upon subsequent fishing effort;
   - water depth, sea state, weather, visibility.

7. **Damage or loss attributed to:** Party believed to be responsible plus reason for allocating responsibility should be given.

8. **Supporting information:**

   - recovered debris;
   - oil sample(s); (If possible a sample of the oil should be collected and given to the local Fishery Officer or a member of the Board staff. The sample should be collected in a clean glass or metal container that has not previously contained any traces of petroleum substances. If the container lid contains any plastic or rubber, the container mouth should be covered with a metal foil before attaching the lid.)
   - names and addresses of any witnesses;
   - copy of relevant passages from ship's log;
   - photographs of damage.

9. **Description of Property:**

   - condition of property at time of damage or loss;
   - if vessel or equipment damaged, date of purchase or manufacture;
   - if property lost, cost of replacement at equivalent quality.

10. **Nature of income loss:** Claims made for income loss attributable to lost catch will require extensive documentation:

    - estimated time fishing effort curtailed, reduced or displaced,
    - actual volume of catch during this period,
    - recorded average catch (and landed value) of the vessel fishing the same gear and
    - species at an equivalent time of year during the previous three years,
    - estimated income loss due to loss of catch.

    Other income loss claims due to a reduction in anticipated income will require similar documentation on past vs. actual earnings.

11. **Other Sources of Compensation:** In the event that compensation from other sources is received for the loss or damage in question, the value of any award determined by the Boards would be reduced by the amount of such other compensation awarded. The claimant is required to provide the name of the source and the amount received or to be received.

12. **Amount of Claim:** Costs and/or expenses must be separated for individual items and supported by signed invoices or estimates:

- for damaged property, estimated costs of restoration or repair must be broken down into cost for parts and labour

- for lost property, estimated cost of replacement at equivalent quality.

13. **Date of claim made to responsible party:** A copy of the claim forwarded to the offshore operator showing the date of transmittal must accompany this claim form. In addition, copies of all subsequent correspondence with the company should be attached.

14. **Declaration:** A claims form will not be accepted unless the declaration is made and signed by or for the claimant witnessed by a third party.

Additional information may be requested in order to process the claim. Failure to provide complete information may result in the rejection of a claim, or affect the amount awarded.

Declaration forms may be obtained at the following addresses:

Canada-Newfoundland Offshore Petroleum Board
Fifth Floor, TD Place
140 Water Street
St. John's, NF A1C 6H6
Telephone: (709) 778-1400
Fax: (709) 778-1473
E-mail: postmaster@cnopb.nf.ca

Canada-Nova Scotia Offshore Petroleum Board
Sixth Floor, TD Centre
1791 Barrington Street
Halifax NS B3J 3K9
Telephone: (902) 422-5588
Fax: (902) 422-1799
E-mail: postmaster@cnsopb.ns.ca

Review of Offshore Oil-spill Prevention and Remediation Requirements and Practices in Newfoundland and Labrador

December 2010

Appendix XVIII

Portion of the Standing Senate Committee Report on Offshore Drilling Operations - Executive Summary and Recommendations (Released August, 2010)

Portion of the Report "Facts Do Not Justify Banning Canada's Current Offshore Drilling Operations: A Senate Review in the Wake of BP's Deepwater Horizon Incident"

Executive Summary

For three months this spring and summer (April 20 to July 15, 2010), people around the world have been exposed 24/7 to the shocking spectacle of crude oil gushing uncontrolled into the Gulf of Mexico, threatening to foul sensitive ecological wetlands, pristine beaches, valuable fishing beds and vast bird and other wildlife sanctuaries. Thanks to the print, electronic and social media, BP's Deepwater Horizon disaster and the ongoing saga of trying to stem the "Black Tide" resulting from the blow-out of its Macondo offshore well has played out in a very public and dramatic way. Few could avoid seeing the non-stop video portrayal of thick black oil gushing into the Gulf waters from the breached well-head pipe some 5,000 feet below the surface. There were ultimately, as well, daily scenes of seabirds covered with the sticky, black substance.

Reactions around the globe have been many and varied. United States President Obama himself has been directly involved, visiting the site on several occasions and issuing highly charged comments and statements on a regular basis, and he has ordered an indefinite moratorium on deepwater offshore drilling, not only in the Gulf of Mexico but everywhere in the American offshore. BP's CEO, Tony Hayward, has been forced to resign his position. Activists have described the incident as possibly the greatest environmental disaster of all time. Some interest groups have supported the President's call for a drilling moratorium. Many others have opposed it. In countries with thriving oil and gas offshore exploration and development industries, debates as to whether to drill or not to drill are now ongoing. In most of these nations, urgent reviews of the regulatory regimes governing offshore operations are being conducted. At the same time, citizens in these nations are expressing consternation about “What if it happens here?” or “Can it happen here?”, and “Are we exposed and what is our response capacity?.

Canada is no exception. Following the explosion of BP’s Deepwater Horizon on April 20th, 2010 killing 11 workers, injuring 28 others and causing literally millions of barrels of crude oil to spew uncontrolled into the Gulf of Mexico, the reaction in Canada was immediate and, in some cases, extreme. Not only was there concern that the “Black Tide”, propelled by ocean currents, might find its way to Canadian shores, but also Canadian wildlife proponents worried about the fate of Canada’s migratory birds, including the legendary loon, which make their way south to winter and nest in the welcome marshes of Louisiana and in other Gulf Coast wetlands. As well, there was immediate public focus on Canada’s “substantial” offshore oil and gas industry. Without fully understanding the nature and scope of Canada’s offshore industry, many Canadians worried out loud, “What about drilling in and under our precious Arctic ice and waters, off the environmentally sensitive coast of British Columbia and beneath the frigid, and in many cases deep waters off the coast of Atlantic Canada?” By early May, a significant percentage of Canadians were said to be advocating an immediate, albeit temporary, halt to all offshore drilling and production activity in Canada. Many called for a permanent suspension of Canadian offshore operations. At the same time, Canadian federal and provincial regulators and legislators, led by the National Energy Board, began immediate reviews of our offshore regulatory regimes. They also dispatched task forces to monitor the disaster response operations in the Gulf of Mexico, to witness or participate in the investigations undertaken to determine what went wrong and to attempt to identify lessons to be learned for Canada from BP’s unfortunate incident.

Given the often conflicting media and other reports respecting the BP disaster and the propensity of citizens and governments to rush to judgement after major disasters, the Standing Senate Committee on Energy, the Environment and Natural Resources decided on May 26th to launch a relatively brief series of fact-finding hearings designed to determine as accurately as possible, within the available time frame, the current status of Canada’s offshore oil and gas exploration and development industry, including the nature of the applicable regulatory regime(s) and Canada's present offshore disaster response capability. The idea was to either allay or validate the said fears of Canadians and to outline for them the "actual state of play in Canada's offshore", thus permitting them going forward to develop informed opinions.

During the six-week period from May 27 to July 8, 2010, the committee conducted nine public, televised hearings, heard the testimony of some 26 witnesses representing all or most interest groups, reviewed substantial documentation and held several in camera sessions to review the evidence. The committee's findings and recommendations are set forth in the body of this Report. There is no doubt that Canada has an active and potentially more active offshore oil and gas exploration and development industry, one which is of significant importance to the economic wellbeing of Canada at large and particularly of those provinces where offshore activity is currently taking place. The committee believes it is important to note that at present, such activity is only taking place in the offshore Atlantic waters adjacent to Newfoundland and Labrador, and Nova Scotia. In fact, there is only one active offshore deepwater drilling operation currently in process, namely Chevron's Lona O-55 exploratory well in the Orphan Basin of the Atlantic Ocean, some 430 km northeast of St. John's, Newfoundland. There are also several oil and gas development and production activities ongoing in the Atlantic offshore region. There is also a standing moratorium on any offshore exploration and drilling activities off the sensitive George's Bank.

As to the Arctic offshore, including the Beaufort Sea, there is no drilling currently taking place. Licences have been issued which do contemplate future drilling activity in Arctic waters, but no drilling has as yet been approved. It is anticipated that activity will begin in 2014.

On the West coast, in the Pacific Ocean waters off British Columbia, no offshore activity is taking place. A moratorium on Canadian West coast offshore operations was implemented in 1972 and continues in effect with both federal and provincial approval. No exploratory or drilling licences have been issued.

Meantime, the committee determined that Canada's offshore industry is subject to a regulatory regime that is modern, up-to-date and among the most efficient and stringent in the world, as compared with those in effect in other nations with active offshore industries. Canada's applicable legislation, rules and regulations, both for the Arctic and elsewhere, are presently under full review by the National Energy Board and Canada's regulators have processes in place to ensure that Canada benefits to the maximum from any and all lessons to be learned as a result of the BP disaster.

The committee considered whether it would be appropriate to recommend a temporary ban on or suspension of the above-mentioned Chevron deepwater drilling operation in the Orphan Basin. No evidence was adduced to justify any such ban or suspension and the committee is recommending that the said Chevron operation continue as planned, under close scrutiny and supervision by the regulators and with great caution and use of state-of-the-art technology in light of the Deepwater Horizon incident. In addition, special attention should be brought to bear to ensure Chevron's oil spill response plans are adequate in the circumstances. Finally, the committee notes that the environment in which the Chevron exploratory drilling operation is taking place differs substantially from that where the Deepwater Horizon incident occurred in the Gulf of Mexico, not far from numerous ecologically sensitive wetlands and important fishing grounds and wildlife sanctuaries.

The committee has certain concerns about present offshore disaster response planning and capacity in Canada and discusses these in this Report. Research and development spending by the major oil companies is currently substantial, but the committee believes it should be increased, if possible, with emphasis on new and better technology for dealing with deepwater blow-outs and responding to catastrophic spills.

Generally, the committee recognizes that offshore exploration and development in the oil and gas industry is a highly risky and costly business. The need to balance the risk factors with the need for energy security and other economic considerations, plus the potential consequences of a major crude oil spill are obvious. Over-regulation and excessively rigid safety requirements could potentially discourage the petroleum industry from investing the massive sums of money already required to participate successfully in this complex business. The committee heard sufficient evidence to make it comfortable with Canada's (federal and provincial) approach to striking this risk/reward balance and with its new judgment-based and goal-oriented regulatory approach. Canada is a leading participant in the International Regulators Forum, a group of offshore industry regulators from the most active offshore drilling nations, including Norway, the United Kingdom, the United States, Australia, New Zealand, the Netherlands and Brazil. Interestingly, none of these nations have called for or imposed bans on current offshore drilling operations within their jurisdictions following the BP incident. One concern expressed by the committee in this Report relates to Canada's laws governing the liability and responsibility for loss and damage, including economic loss and environmental cleanup expenses following a major oil spill arising during an offshore drilling operation. Canadian rules in this area are somewhat confused and conflicting, and require a careful review and, at the very least, an upgrading to take into consideration present day economic realities.

In conclusion, the committee wishes to assure Canadians that Canada's offshore oil and gas industry is in good hands, that we could not identify any justification for a temporary or permanent ban or moratorium on current offshore operations, that Canada's regulatory regime is a good one, which is continually subject to upgrading and improvement based on experience such as the BP incident, and that any future offshore operations authorized to take place in Canadian jurisdiction, be they in Arctic waters, off the Pacific Coast or off Atlantic Canada, will be well and carefully regulated and controlled, given the experience of the Deepwater Horizon incident in the Gulf of Mexico. There are indeed areas where the committee has concerns and where improvements can be introduced on the legal, regulatory and operational levels. These are clearly outlined in this Report.

List of Recommendations

1) The committee does not recommend banning current offshore drilling either permanently or temporarily while Canada's government regulators re-evaluate the regulatory regime, safety measures and contingency plans in light of the Deepwater Horizon oil spill.
2) The committee recommends exploring in greater detail the structure and role of the offshore petroleum Boards to determine whether there may be in fact a material conflict between regulatory roles.
3) The committee recommends a thorough discussion by regulators and industry respecting whether and under what circumstances relief wells should be prescribed. As was the case in the Gulf of Mexico, a relief well can take several months to complete; therefore, it follows that current US relief well drilling requirements appear to be inadequate to maximize oil slick containment and minimize environmental damage. As well, drilling two exploratory wells instead of one may inadvertently increase the likelihood of a blowout.
4) The committee recommends that there be greater collaboration between all those responsible for responding to an oil spill in developing, preparing and practicing in advance of an event.
5) The committee recommends that all offshore operators be required to organize Tier Three spill response tabletop drills at regular intervals.
6) The committee recommends a comprehensive review of the issue of liability, including whether the thresholds should be adjusted to reflect current economic realities.